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Auxiliary Feedwater System Aging Study

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Prepared for
U.S. Nuclear Regulatory Commission

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ABSTRACT

This report documents the results of a study of the Auxiliary Feedwater (AFW) System that has been conducted for the U. S. Nuclear Regulatory Commission's Nuclear Plant Aging Research Program. The study reviews historical failure data available from the Nuclear Plant Reliability Data System, Licensee Event Report Sequence Coding and Search System, and Nuclear Power Experience data bases. The failure histories of AFW System components are considered from the perspectives of how the failures were detected and the significance of the failure. Results of a detailed review of operating and monitoring practices at a plant owned by a cooperating utility are presented. General system configurations and pertinent data are provided for Westinghouse and Babcock and Wilcox units.

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LIST OF ACRONYMS

The following is a list of acronyms that are used frequently throughout this paper.

ACP	Auxiliary control panel
AFW	Auxiliary feedwater system
AMSAC	Anticipated transient without scram mitigating system actuation circuit
AOV	Air-operated valve
ASME	American Society of Mechanical Engineers
ASE	Average system effect
B&W	Babcock and Wilcox
BDIV	Blowdown isolation valve
BMDLCV	Bypass motor-driven pump level control valve
BWR	Boiling water reactor
CMCV	Common miniflow check valve
CST	Condensate storage tank
DCV	Discharge check valve
DDP	Diesel-driven pump
EHOV	Electrohydraulic-operated valve
ESF	Engineered safety feature
ESW	Emergency service water
FC	Failure count
FSAR	Final safety analysis report
FWIV	Main feedwater isolation valve
GV	Turbine governor valve
I&C	Instrumentation and control
INEL	Idaho National Engineering Laboratory
INPO	Institute for Nuclear Power Operations
IST	In-service test
LCO	Limiting condition for operation
LCV	Level control valve
LCVCV	Level control valve check valve
LER	Licensee Event Report
LOFW	Loss of main feedwater
MCB	Main control board
MCC	Motor control center
MCV	Miniflow check valve
MDLCV	Motor-driven pump level control valve
MDP	Motor-driven pump
MFCV	Main feedwater check valve
MFLB	Main feed line break
MI	Maintenance test/inspection
MOV	Motor-operated valve
MOVATS	Motor Operated Valve Analysis and Test System™
MSIS	Main steam isolation signal
MSLB	Main steam line break
MSSV	Main steam safety valve
NPAR	Nuclear Plant Aging Research
NPE	S. M. Stoller's Nuclear Power Experience
NPRDS	INPO's Nuclear Plant Reliability Data System
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission

NSSS	Nuclear steam supply system
OP	Operating procedure
ORNL	Oak Ridge National Laboratory
PORV	Power-operated relief valve
PS	Pressure switch
PWR	Pressurized-water reactor
PZR	Pressurizer
RCP	Reactor coolant pump
RCS	Reactor coolant system
RGSC	Ramp generator/signal converter
RSD	Relative system degradation
SB	Station blackout
SCV	Pump suction check valve
SG	Steam generator
SI	Safety injection
SOV	Solenoid-operated valve
SSIV	Steam supply isolation valve
SSV	Steam supply valve
ST	Surveillance test
TDLCV	Turbine-driven pump level control valve
TDP	Turbine-driven pump
T&T	Trip and throttle valve (for AFW turbine)

1. INTRODUCTION AND SUMMARY

The Nuclear Plant Aging Research (NPAR) Program was established by the Office of Nuclear Regulatory Research of the Nuclear Regulatory Commission (NRC) to identify sources of degradation, their effects, and available methods of degradation and failure detection.

Nuclear plant safety-related systems are composed of combinations of electrical and mechanical pieces of equipment that are intended to function in a coordinated manner to support and/or allow normal plant operation while fulfilling specific roles in the mitigation of anticipated transients and design basis accidents. The NPAR Program has identified several types of components for detailed study. The studies of these individual components have identified component-specific failure modes and causes, associated stressors, and available monitoring methods.

This review of the auxiliary feedwater (AFW) system, used at pressurized-water reactor (PWR) plants, has been conducted under the auspices of the NPAR Program. The primary purposes of the review were to

1. determine the potential and historical sources and modes of failure within the AFW system,
2. identify currently applied means of detecting known sources and modes of degradation and failure, and
3. evaluate the general effectiveness of the current monitoring practices and identify specific areas where enhancements appear needed.

This study, which was conducted by Oak Ridge National Laboratory (ORNL), consisted of the following elements:

1. identification of general types of AFW system design configurations,
2. analysis of historical failure data, and
3. detailed review of a cooperating utility's AFW system design and their current operating and monitoring practices.

1.1 BACKGROUND

Particularly since the Three Mile Island 2 accident, the AFW system has historically been recognized as critical to successful mitigation of plant transients and accidents. In recent years, operating incidents involving failures of AFW system components have been among the leading events identified in the "Precursors to Potential Severe Core Damage Accidents" reports,[1] which identify the leading risk significant events for calendar years. In the years 1984 through 1986, seven of the top ten events at PWRs, from a core damage risk standpoint, involved partial or total failure of the AFW system.

Operational problems with the AFW system have been diverse in nature. Information Notices and Bulletins and other mechanisms of information feedback and regulatory action have been issued by the NRC that identify problems that have been experienced with AFW systems. The following are provided as examples of failures involving the AFW system that have resulted in NRC feedback.

Bulletin 85-01, "Steam Binding of Auxiliary Feedwater Pumps," discussed a number of historical events in which backleakage of hot feedwater into the AFW system had resulted in overheating of AFW discharge and suction piping and steam binding of AFW pumps. The bulletin required the establishment of routine monitoring of AFW piping for backleakage and the development of procedures to identify backleakage and restore the system to operable condition should it occur.

Bulletin 85-03, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," was issued primarily as a result of the June 9, 1985, loss of main feedwater and AFW at the Davis-Besse plant. AFW was lost because of improper torque and limit switch settings on AFW system motor-operated valves. (This episode was also discussed in Information Notice 85-50.)

Information Notice 86-01, "Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity and Water-Hammer Damage," was issued to provide information feedback on the November 21, 1985, failure of several check valves in the main feedwater system at San Onofre 1. Failure of these check valves allowed draining of the steam generators (SGs) and prevented AFW from reaching the SGs until gate valves were closed by operator action. Sufficient draining occurred to result in condensation-induced water hammer when AFW began to refill the drained Main Feedwater piping.

Information Notice 86-09, "Failure of Check and Stop Check Valves Subjected to Low Flow Conditions," was issued as a result of a number of failures of stop check valves in the steam supply piping to the AFW turbines at the Turkey Point Units. The failures occurred as the result of chattering induced by low flow that resulted from leakage past motor-operated valves in series with the stop check valves.

Information Notice 86-14, "Overspeed Trips of AFW, HPCI, and RCIC Turbines," issued following the Davis-Besse event in 1985, discussed several types of turbine overspeeding events that had occurred historically. A review of overspeed events of turbine-driven pumps was conducted by the NRC Office of Analysis and Evaluation of Operating Data. This review resulted in the publication of "Operational Experience Involving Turbine Overspeed Trips," AEOD/C602, which in turn provided the basis for this Information Notice.

Information Notice 87-53, "Auxiliary Feedwater Pump Trips Resulting from Low Suction Pressure," was issued as a result of low-suction pressure trips of AFW pumps at several plants because of suction pressure fluctuations that resulted from a variety of transient system conditions.

These problems are examples of the diverse types of failures experienced in the AFW system. Numerous other operating experiences have been fed back to industry through both the NRC and the Institute of Nuclear Power Operations.

In reviewing the role that aging plays in failures such as these, there are some important points to be considered. First of all, a combination of factors, including design, maintenance, operation, aging, and other considerations may be involved. These factors are not necessarily independent from one another. For example, a poorly designed component or system may require that it be operated in a manner that is not necessarily conducive to extended service of either that component or other components.

An example of this can be seen in many AFW system designs in relation to flow paths available to a pump. If the only full flow path available for the pump is to the SGs, required monthly or quarterly testing will normally be done under recirculation flow only. It has become clear that running these pumps at low flow rates is deleterious to the pump and pump life.[2] But delivering flow to the SGs also has undesirable effects in terms of nozzle thermal stress. The result is that the pumps are run under recirculation flow only for testing (as well as often being run at low flow rates during routine plant startup and shutdown) and accumulated wear results. If pump failure ultimately results, it would be difficult to ascribe the failure to a particular cause such as aging. In reality, the failure may result from the combination of poor system design, undesirable operating conditions, insufficient maintenance attention, excessive test frequency requirements, etc.

This difficulty of determining the extent to which a particular failure is aging-related extends to most component failures. The only failures that can be readily dismissed as not being aging-related are those that occur within a short time after a component is placed in service. The quantification of "short time" depends upon the particular component and its operating conditions. For example, through-wall erosion of piping downstream of a control valve would normally be viewed as an aging-related failure. However, a failure of this nature could occur in a time span ranging from days to decades, depending upon the piping material and layout, service conditions, and other factors.

A second point relative to aging is pertinent when considering systems. A system, as noted above, is composed of a group of components, such as pumps, valves, motors, piping, etc. The system ages only as the individual components age. The types of components most subject to wear and aging may vary significantly from system to system, however. Furthermore, even for the same type of system, certain components may experience substantial service wear at one facility and very little at another because of the combination of design, maintenance, and operating factors involved. Other studies performed under the NPAR Program address important components within the AFW system and the aging stressors for these individual components.

A third important factor in determining the ORNL approach was an Idaho National Engineering Laboratory (INEL) study that reviewed historical failure data from the Institute of Nuclear Power Operation's Nuclear Plant Reliability Data System (NPRDS) (similar to the NPRDS data that were reviewed by ORNL in this study) and made judgments as to whether individual failure episodes were aging related.[3] The INEL report was based upon some of the same failure data that were used in this study (the review of failure data is discussed in Chap. 4).

Because of these factors, the ORNL approach to the AFW system study has focused on how and to what extent the various AFW system component types fail, how the failures have been and can be detected, and on the value of existing testing requirements and practices, rather than attempting to focus on the extent to which aging (vs design or operating practices, for example) is responsible for failure or degradation.

On the other hand, in the review of a particular plant's design and operating practices, it is possible to determine, in a relative manner, the extent to which design, test, and operating requirements can contribute to aging for particular components. For instance, if a check valve routinely experiences low flow rates during system operation, and is located just downstream of a flow disturbance, a judgement can be made that the particular valve will be likely to experience a relatively high rate of service wear compared with a similar valve in more optimal conditions. Aging concerns of this nature are addressed in this study. However, the individual component configuration and operating conditions may vary considerably from plant to plant, and even within the same system.

1.2 SUMMARY OF RESULTS

The analysis of historical failure data and the detailed review of a cooperating utility's AFW system design and monitoring practices provided complementary results. The single largest source of historical AFW system degradation, based upon the historical failure data review, is the turbine drive for AFW pumps. Note that the turbine proper has been a relatively reliable and rugged piece of equipment. However, the turbine auxiliaries, including the governor control and trip and throttle valve, have contributed substantially to the overall turbine problems.

The failures of valve motor and air operators combined were found to have resulted in approximately the same level of degradation of the AFW system as the turbine drives alone. Pump failures and check valve failures were also significant contributors to system degradation.

For each of the component types and for the various sources of component failures, the methods of failure detection were designated and tabulated. The most notable feature of this aspect of the study was that instrumentation and control (I&C) related failures dominated the group of failures that were detected during demand conditions (as opposed to failures detected as the result of periodic monitoring or routine observations made by operators or other personnel). This finding was corroborated by the detailed review of the operating plant's monitoring practices, because many of the potential failure sources not detectable by the current monitoring practices were related to the I&C portion of the system.

It was also observed that a number of conditions related to design basis demands are not being periodically verified. Examples of these include pumps not being verified at design flow/pressure conditions, turbines not being verified to be capable of delivering required flow at low steam pressures, various control sequences not being checked, and automatic pump suction transfers not being tested.

Another observation was that some components or certain parts or aspects of components appear to be tested in excess of what failure history indicates to be appropriate. In contrast, as can be gathered from comments above, other aspects of certain parts of AFW systems are either never tested or receive less than thorough testing. Enhanced testing requirements appear to be needed to reduce excessive testing while at the same time ensuring that thorough performance verification is conducted periodically.

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2. GENERIC AFW SYSTEM DESIGN

2.1 INTRODUCTION

AFW system designs in U.S. PWRs vary considerably, in part because of the general evolution of design requirements imposed by the NRC, but largely because the AFW system is generally designed by the plant's Architect-Engineer. As a result, even two plants with similar nuclear steam supply systems (NSSSs) that are constructed during the same time frame can have significant differences in AFW system design. To provide some insight into AFW system designs and the bases for those designs, both generic and plant-specific discussions are provided. Section 2.3 briefly discusses generic system functional requirements and some typical designs and serves as an introductory overview of the AFW system. More specific insight into the design of an individual plant's system is provided in Chap. 3.

2.2 SYSTEM BOUNDARIES AND INTERFACING SYSTEMS

For the AFW system to accomplish its design requirements, proper functioning of interfacing system components is required. The AFW system interfaces with a number of systems, including but not limited to the

1. main feedwater system,
2. main steam supply system,
3. SG blowdown system,
4. emergency service water (ESW) system,
5. engineered safety features actuation system, and
6. electrical and instrumentation power distribution systems.

The components that comprise the interface for the AFW system have been reviewed, in part, by this study. The detailed review of a specific plant's AFW system (Chap. 3) included a review of the interfacing components; however, the failure data search (Chap. 4) did not address these interfacing components. The interfacing components were not included in the failure data search because the system affected by the failure of these components would typically be assigned as the system to which the components belonged, rather than the AFW system. However, failure of an interfacing system component can degrade the associated AFW train(s) just as severely as failure of a component designated as an AFW system component.

2.3 AFW SYSTEM FUNCTIONAL REQUIREMENTS AND TYPICAL DESIGNS

2.3.1 Generic Functional Requirements

The AFW system's principal role is to support removal of stored and decay heat from the reactor coolant system (RCS). The SGs act as a heat sink during both normal operation and following reactor trips. During normal operation, the main feedwater system provides feedwater to the SGs, where it is converted to steam and then used to drive the main turbine and provide process steam for various plant equipment. During normal power operation, the AFW system is in standby (except when in test). Following an operating transient or accident, as well as during routine startups and shutdowns,* the AFW system is used to provide a safety-related source of water to the SGs. The water delivered by the AFW system is heated and vaporized in the SGs. Steam thus generated can be released to the atmosphere through the safety-related main steam safety valves or atmospheric dump valves or to the atmosphere and/or condenser through nonsafety-related steam dump valves.

The AFW system must not only support the heat removal but allow the heat removal to take place in a controlled manner even under design basis accident conditions. There are four general functional requirements of the AFW system:

1. provide flow to intact SGs following design basis transients/accidents,
2. isolate flow to faulted or ruptured SGs,
3. maintain a liquid barrier between the RCS and the environment following design basis accidents to ensure that any primary to secondary tube leakage is "scrubbed" before release, and
4. support normal startup and shutdown evolutions.

As noted, the AFW system is used, at most plants, in support of normal plant startup and shutdown. However, this is not the primary basis for its design. Rather, it is specifically designed for the mitigation of the consequences of design basis transients and accidents, including loss of main feedwater (LOFW), main feed line break (MFLB), main steam line break (MSLB), small- and large-break loss-of-coolant accidents, SG tube rupture, and others. In addition, proper functioning of the AFW system is critical to the ability of a plant to deal with an important accident condition, station blackout, which has not been historically treated as a design basis accident.

2.3.2 Design Configurations

A broad range of AFW system designs exist at operating plants. Figures 2.1–2.3 provide flow diagrams that are representative of the cross section of existing PWR AFW systems. This section discusses some general design configuration features. Because of the diversity of AFW system designs, it is difficult to depict adequately AFW systems in general. A compilation of operating plant pump and driver, valve and valve operator, and other general configurational information for Westinghouse and Babcock and Wilcox (B&W) plants is provided in Chap. 5.

2.3.2.1 Pump suction sources

Most plants have a dedicated storage tank, commonly designated as the condensate storage tank (CST) that is used to maintain a reserve inventory of high-quality water for the AFW pumps. The inventory available for the AFW pumps may actually come from multiple sources, depending upon plant design. For purposes of this discussion, the normal source(s) of water will be referred to as the CST. Plants under Standard Technical Specifications have a designated inventory that must be maintained in the CST during Modes 1–3. The CST is safety grade and seismically qualified at some plants, but not at others. Normal system alignment would have the suction flow path from the CST to the

*At some plants, nonsafety-related startup feedwater systems are available and used to support plant startup and shutdown in lieu of the AFW system.

ORNL–DWG 90–3300 ETD

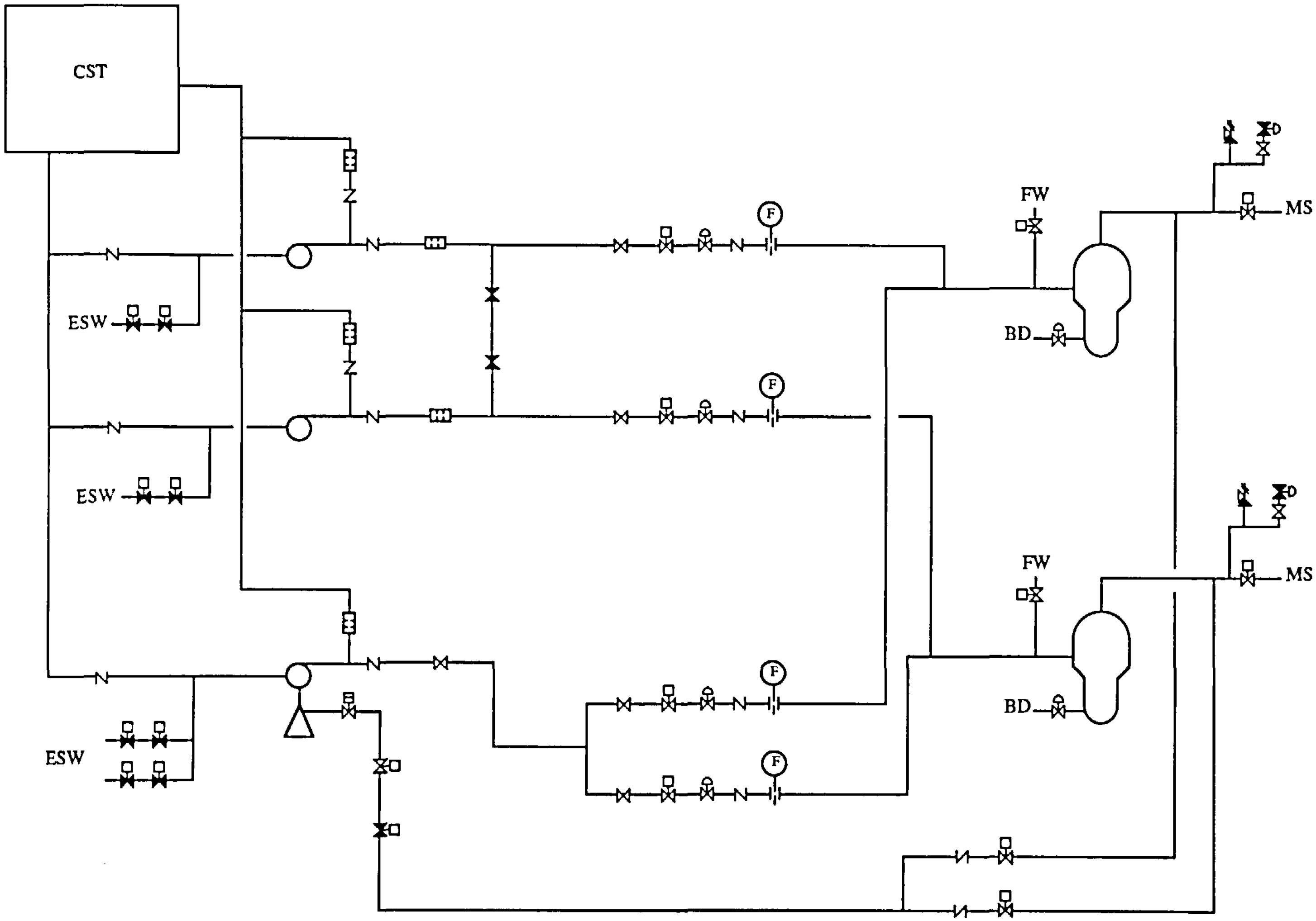

Fig. 2.1. AFW system for two-loop plant.

ORNL–DWG 90–3301 ETD

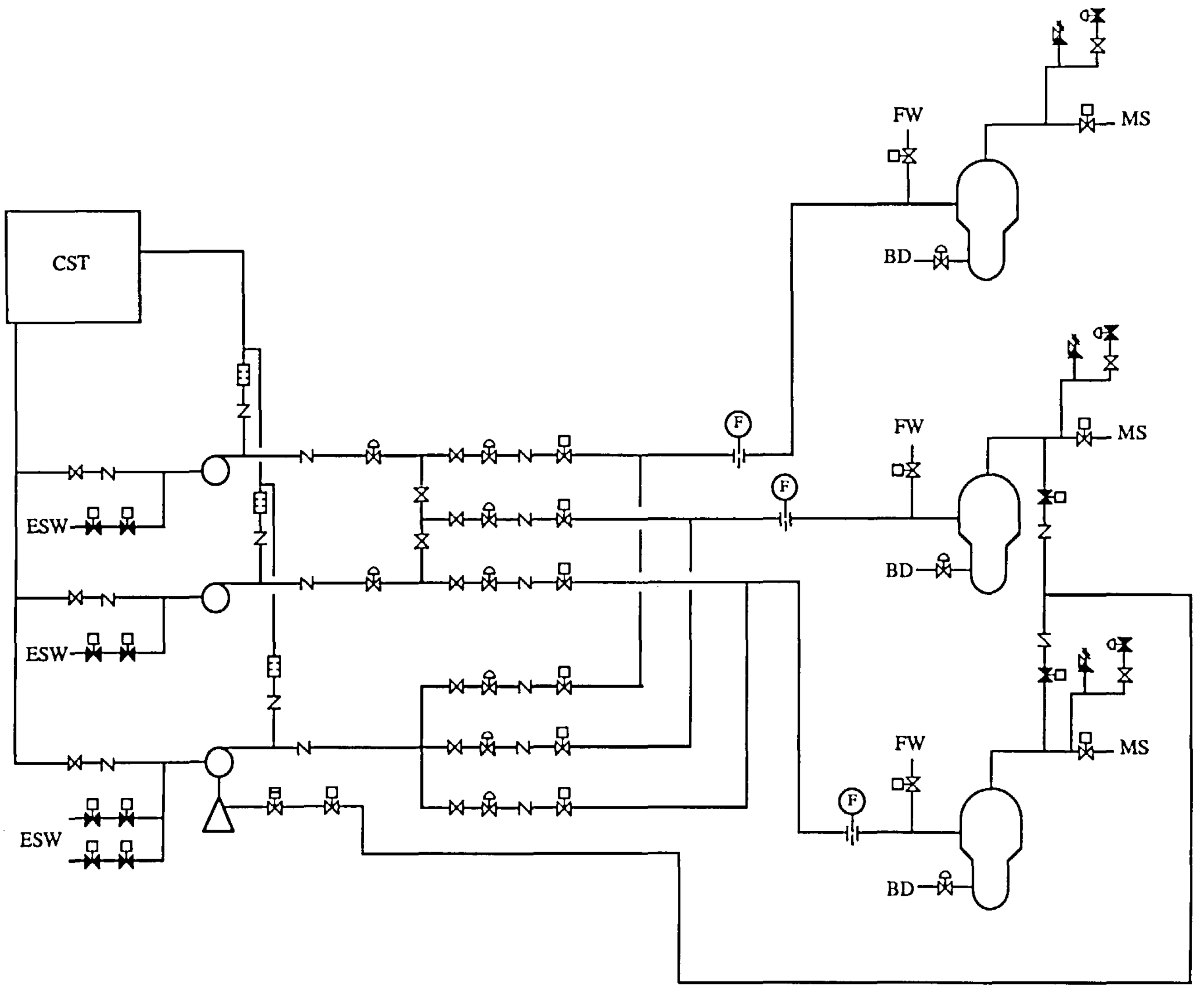

Fig. 2.2. AFW system for three-loop plant.

ORNL–DWG 90–3302 ETD

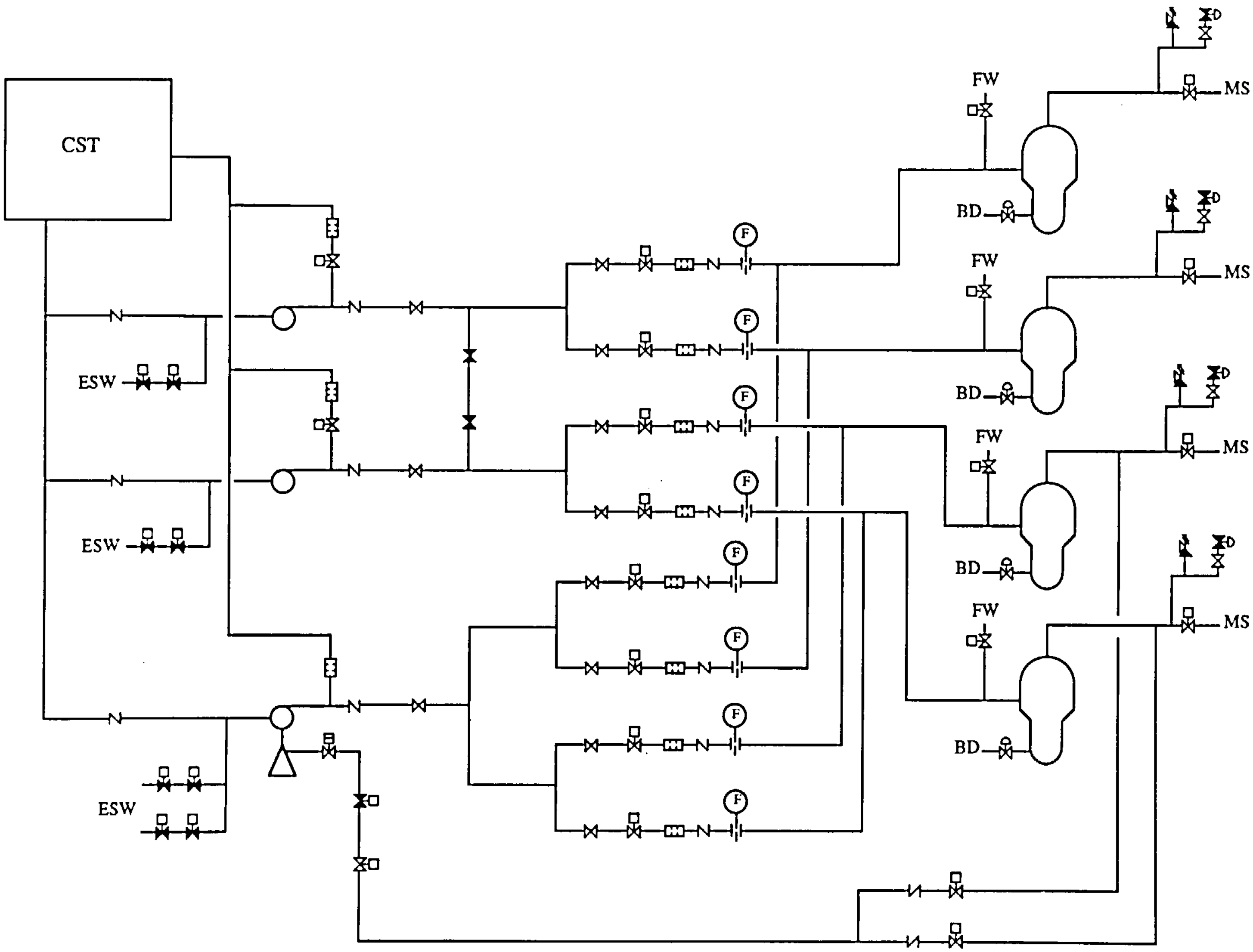

Fig. 2.3. AFW system for four-loop plant.

AFW pumps open, and in fact, manual valves in the suction flow path may be required to be locked open.

The majority of plants also include a backup source of water, normally from the plant's ultimate heat sink system, which is commonly called the emergency service water (ESW) system. Depending upon plant design, the ESW may be the only safety-grade source of water (e.g., if the CST is nonsafety grade). Switchover from the CST or other normal supply sources to the ESW may be either automatic or manual. Low suction pressure is the normal switchover condition monitored for plants including automatic switchover. Some plants use suction pressure transmitters to provide AFW pump tripping under low suction pressure conditions (this trip function has been removed at several plants and replaced with an alarm only to avoid spurious tripping). Even for plants that do not use automatic switchover, low suction pressure instrumentation may furnish main control board indication and annunciation to provide the operator with an indication of the need for suction transfer. CST or other normal water source level instrumentation also provides the operator with suction status. For plants with manual switchover only, some provide totally remote switchover capability, while others require local valve realignment.

Check valves are normally included in the normal suction supply lines to prevent flow reversal into the CST if ESW must be used as the suction source. In cases where the normal suction sources are nonsafety grade, the suction check valve forms the boundary between safety-grade and nonsafety-grade portions of the AFW system.

2.3.2.2 Pumps

All three flow diagrams (Fig. 2.1–2.3) indicate two motor-driven and one turbine-driven pump per plant. This is the most typical configuration; however, there are a number of pump combinations at operating plants. In addition to variations in the number of pumps per unit, the type of drivers vary. There are various combinations of motor-, turbine-, and diesel-driven pumps in the AFW pump population. Among Westinghouse and B&W plants included in the ORNL failure data base (discussed in Chap. 4), six different AFW system pump combinations were identified. A summary of general pump and SG configuration information for the plants in the failure data base is provided in Tables 2.1 and 2.2. Plant-specific SG and pump configuration information is provided in Chap. 5.

Motor-driven pumps receive their power from emergency busses (there are some plants which designate one or more nonsafety-related motor-driven pumps as part of the AFW system; however, these pumps were not included in this study). Pump breaker closure not only starts the associated pump, but auxiliary contacts for the breaker are often used to provide control signals to other AFW system features.

Steam for the turbine-driven pumps is supplied by one or more (typically two) SGs. There are a number of steam supply control arrangements. Some plants start the turbine by opening a normally closed trip and throttle (T&T) valve, located immediately adjacent to the turbine. Other plants leave the T&T valve normally open and start the turbine by opening one or more upstream isolation valves. Some plants have pressure control valves in the steam supply line that limit steam pressure available to the turbine; at other plants, full steam pressure is available to the turbine (less line and governor losses). Turbine speed and therefore pump flow, are controlled by turbine governor valve position. The governor valve operator receives control signals typically based on turbine speed and, for some controllers, flow or other differential pressure measurement (e.g., steam supply to pump discharge differential pressure).

Some plants include nonsafety-related pumps that are similar in function to the AFW pumps. Where available, these pumps are used in support of normal startup/shutdown (in some cases, they are referred to as startup feed pumps). While these pumps have not been considered in this study, their availability can have a substantial impact upon the service

Table 2.1. Pump combinations for failure data base plants

Configuration	Two-loop plants	Three-loop plants	Four-loop plants	Total
One MDP, one TDP	5	1	0	6
Two MDP, one TDP	8[a]	9	20	37
One MDP, one DDP	0	0	1	1
One TDP, one DDP	0	0	1	1
Two TDP	1	0	1	2
Three TDP	0	2[a]	0	2
Total	14	12	23	49

[a] Note: Includes units sharing one or more pumps.

Table 2.2. Number of motor- and turbine-driven pumps for failure data base plants: summary

Configuration	Two-loop plants	Three-loop plants	Four-loop plants	Total
Total MDPs	17	19	41	77
Average number MDPs / plant	1.50	1.58	1.78	1.65
Total TDPs	15	13	23	51
Average number TDPs / plant	1.07	1.33	1.00	1.10

wear of AFW pumps and other AFW equipment because the AFW pumps would not be routinely used for startup/shutdown purposes. The nonsafety-related pumps can also substantially enhance the availability of postaccident secondary cooling. As an example, following the June 1985 Davis-Besse loss of feedwater and AFW, feed flow to the SGs was ultimately restored by use of a startup feed pump.

2.3.2.3 Pump discharge and recirculation flow

Pump discharge lines include flow paths to the SGs and minimum recirculation flow paths. The recirculation flow may be controlled by orifices, line size, control valves, or a combination of these means. Some plants include both a minimum recirculation flow path and a full-flow test loop, both of which recirculate flow to the CST or other suction source. Other plants use a common flow path for both, while others do not have a full-flow test loop but only a miniflow recirculation path. A tabulation of full-flow test loop availability is provided in Chap. 5.

Recirculation flow paths, both of the full-flow and the miniflow variety, may include valves that automatically isolate under certain conditions. For instance, plants with full-flow recirculation test loops typically include automatic isolation valves that close if an automatic start signal occurs. Other plants provide for automatic isolation of the miniflow path if the associated pump is the only available pump or if delivered flow to the SGs is sufficient to provide what has been determined to be adequate for pump protection.

In a number of plants, the miniflow recirculation flow paths include check valves upstream of where the individual pump lines join to form a common recirculation line header. The apparent design function of these valves is to provide train separation, although there are no such valves in some plants. For those plants that do not have these check valves, the apparent rationale is that orifices or other flow-limiting devices would limit cross train flow, thereby eliminating the need for train separation offered by check valves. For a sample of plants for which nominal minimum recirculation flow rates were specified in the FSAR, the flow velocities at check valves in the miniflow lines ranged from 1 to 15 ft/s. While, as noted, the only apparent function of these valves is to provide train separation, those valves that routinely experience flow velocities less than that required for full stroking (estimated to be in the range of roughly 8 to 15 ft/s, depending upon the specific check valve design), can be fairly susceptible to service wear. Inasmuch as testing, if any, associated with the recirculation check valves is to verify that the required flow rate is supported, substantial degradation or failure of these valves may not be detectable.

Valving between the pumps and the SGs provides for control of individual pump flow, flow to specific SGs, and a means of preventing backleakage from the SGs or from main feedwater. The arrangements of valves between the pump discharge and the SGs vary considerably in terms of numbers, operator types, layout configuration, control signal sources, and normal standby position.

Some plants use automatic discharge pressure control valves for motor-driven pumps to provide pump runout protection. These valves may be either normally closed or open and receive a control signal following pump start. The valve control signal is normally geared toward maintaining discharge pressure or flow at a designated setpoint. The capability to adjust the control setting from the main control room may or may not exist. Other plants do not use automatic valve positioning to regulate individual pump flow/discharge pressure; rather, nonadjustable, fixed means, such as cavitating venturis, flow-restricting orifices, or valves locked in a throttled position are utilized. For yet other plants, it is not clear, from FSAR descriptions and other information available, what, if any, pump runout protection, other than operator action is available.

Most pump discharge lines include discharge check valves to prevent reverse flow from other pumps as well as to prevent backleakage of main feedwater. For a sample of plants reviewed, the flow velocities that would be experienced at design flow rates for the motor-driven pumps ranged from 5 to 12 ft/s. Note that when AFW pumps are used during startup/shutdown evolutions, they would normally be run at substantially less than the design flow rates. For the pumps that are used for this service, discharge check valves can be subject to accelerated service wear. Unlike the miniflow check valves, the function performed by these valves is critical to successful system operation.

2.3.2.4 Flow distribution

Pump discharge line configurations normally allow more than one SG to be fed by each pump (although some two-loop plants are arranged such that only one pump normally feeds one SG). All three-loop plants are configured such that all three SGs are fed by all pumps, while most four-loop plants are designed and normally aligned to allow feeding of all four SGs by a turbine-driven pump and feeding of two SGs by each motor-driven pump. Control of flow to individual SGs is provided by a variety of combinations. Motor-, air-, electrohydraulic-, and solenoid-operated valves are used as flow control devices. There are diverse control designs for the valves. Control valves at some plants are normally closed while corresponding valves are normally open at other plants. Those that are normally closed typically receive an open signal on associated pump start or AFW actuation signal. At some plants, the flow distribution valves automatically modulate to maintain a preset flow or SG level; while at other plants, the valves go to a full open or other fixed position and remain there unless repositioned by an operator.

The flow distribution valves may be used as a part of a faulted SG isolation system, which automatically detects and isolates any SG that is depressurized. This system supports the functions of both ensuring that intact SGs can receive AFW flow as well as minimizing the adverse impact of feed or steam line breaks on the RCS and containment. Other plants rely upon flow-limiting devices, such as cavitating venturis, on a temporary basis following a faulted SG event, and ultimately upon operator action to detect and then to isolate flow to the faulted SG. Yet other plants depend solely upon operator recognition and isolation of the faulted SG, with no automatic break detection and isolation or fixed flow-limiting devices available. Note that the valves used in the AFW system to isolate flow are not normally seat leak tested, even if they are classified as containment isolation valves.

Some plants have dedicated AFW SG nozzles, while the AFW discharge lines at other plants connect with main feedwater piping upstream of the SGs. Various combinations of check valves and isolation valves are used to avoid backleakage of hot feedwater or steam into the AFW system. There are typically several check valves, and in some cases, closed isolation valves in series between the pumps and the SGs.

2.3.3 AFW System Starting

AFW systems are started automatically when monitored plant conditions provide indication that AFW operation is warranted. The specific signals monitored, like all other aspects of the AFW system, vary from plant to plant. There are several sources of automatic starting, however, which are fairly common, including safety injection, low SG level, loss of offsite power (typically emergency bus undervoltage), reactor coolant pump trip, and main feed pump trip. Typically, automatic start signals will either start AFW pumps immediately, or as a part of load sequencing. In either case, the pumps are usually started within a minute following the start signal initiation.

AFW start signals also actuate other equipment that is crucial to AFW system success. For example, some plants have normally closed discharge valves that must open to allow flow to reach the SGs. These valves receive an open signal on AFW initiation. Other equipment that is not specifically part of the AFW system may also respond automatically on an AFW start signal. For example, SG blowdown isolation valves may receive an automatic closure signal from the AFW start signal, thereby helping to ensure that the flow delivered to the SGs can be converted to steam (vs draining off without changing phase).

Manual start capability for all AFW pumps is typically provided at the main control board as well as at the remote shutdown panel. Additionally, local stations may be provided for pump starting and stopping.

A typical logic diagram showing the origination of AFW start signals and the equipment actuated as a result is provided in Fig. 2.4. A detailed discussion of AFW system actuation for a specific unit is provided in Chap. 3.

2.3.4 AFW System Operation

Following AFW system starting, whether as the result of automatic or manual starting, the system responds to both manual and automatic control functions. The sources of the control signals are diverse. Flow to the SGs is controllable through valves that open/close/modulate in response to automatic control and/or manual control signals. These signals may be based on flow, level, or pressure. Turbine-driven AFW pump speed is controlled automatically, normally based on flow, differential pressure, speed, and/or other signals. Turbine speed can also normally be controlled by remote manual action.

Typical AFW system design would initiate flow to the SGs automatically at full flow and require operator action to control or isolate flow. However, as noted previously, some plants do have automatic level controls. Some facilities also have an automatic isolation feature that detects and isolates faulted (depressurized) SGs. Other plants incorporate flow-limiting venturis or orifices to prevent excessive flow from being delivered to a faulted SG.

Following a reactor trip, as well as during normal startup and shutdown evolutions in which the AFW system is actuated, the instantaneous flow to the SGs may vary from zero to several hundred gallons per minute. Following a reactor trip, while decay heat load is fairly high, typical practice for a plant with a turbine-/motor-driven pump combination would be to stop the turbine-driven pump following plant stabilization and then control SG level using only the motor-driven pump(s). Under very low decay heat conditions, for example, during routine startup and shutdown, SG feed control practices may vary from plant to plant and even from operator to operator. For example, if there are no specific procedural requirements and demand is low, one operator may elect to "batch" feed the SGs by starting and stopping a pump periodically. Another may also "batch" feed, but leave the pump running in recirculation flow in between batching. A third method would be to continuously feed at very low flow rates, while also maintaining recirculation flow. During these low-flow periods, the minimum number of pumps would be run (the minimum number depending upon plant configuration and specifically how many SGs can be fed by a particular pump). Note that some plants with nonsafety startup feed pumps can avoid running at low flow for protracted periods or repeated starting and stopping of the AFW pumps.

Operating guidance and practices for a specific plant are included in Chap. 3.

2.3.5 Example AFW System Requirements for Various Accident Conditions

The various accident scenarios create somewhat different demands upon the AFW system. To provide some insight into these demands, three types of events, LOFW,

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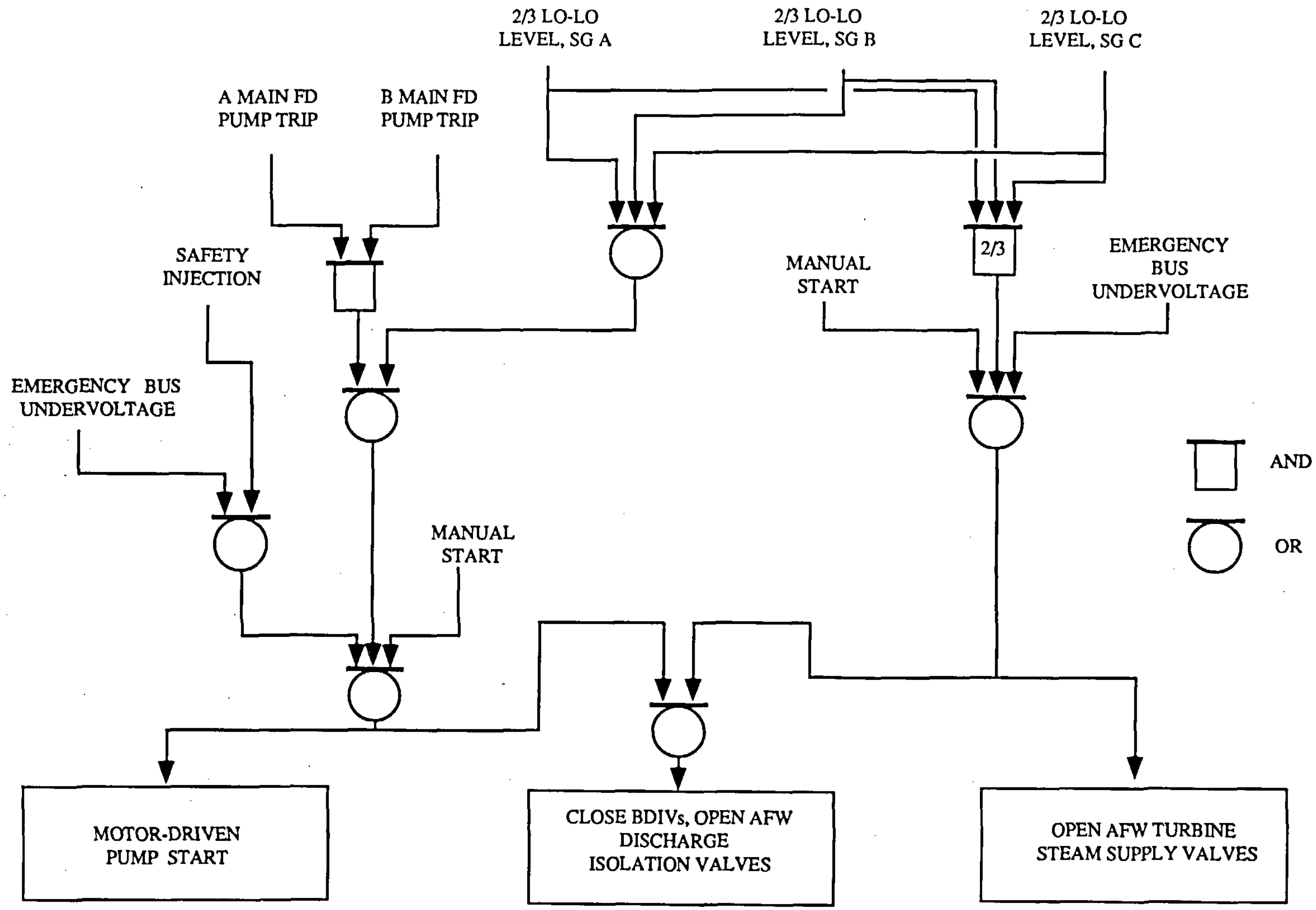

Fig. 2.4. Typical AFW system actuation logic.

MFLB, and MSLB, will be discussed in relationship to the AFW system functions. In considering these events, remember that the general role of the AFW system is to support stabilization of the plant at hot standby conditions, and then to support plant cooldown and depressurization to the point where the residual heat removal system can be placed into service. The discussion of these events is intended to serve to illustrate both this general role and supplementary functions as well.

The following discussions of plant response to various transient/accident conditions are based on general trends noted in the review of the Accident Analysis sections from a number of plants' FSARs. Note that the overall response of one plant to an initiating transient may differ substantially from the response of another plant to the same transient conditions. Furthermore, the plant response, as presented in FSAR analyses, is generally overstated (as a result of conservatism built into licensing based analyses) and is heavily dependent upon modeling methodology. As an example, no control system operation is assumed in safety analyses, unless it would be adverse to the analysis results. In reality, operation of control systems, when available, substantially mitigates overall plant response in most cases.

Note that the response of the parameters monitored (RCS and SG pressure) is very sluggish with respect to AFW initiation; that is, starting of an AFW pump does not create an immediately observable effect. In contrast, the effect of the lifting of a main steam safety valve (MSSV) can be immediately seen for two reasons: relative size and thermodynamic effect. AFW pump capacity is small relative to MSSV capacity. A typical single MSSV is capable of relieving a mass flow rate of roughly two to four times the design mass flow rate of a typical AFW pump. Note that there are several safety valves per SG. Secondly, because the preponderance of heat removal is associated with the vaporization of SG fluid, and because in safety analyses the SG level never falls to a point where no fluid exists, no observable change is associated with delivery of AFW to the SGs. However, failure to deliver AFW to the SGs would have substantial impact on the results of any transient, because the RCS heat sink would degrade and eventually be lost.

2.3.5.1 Loss of main feedwater

The LOFW scenario is an event that can be classified as expected; that is, it is to be expected that all plants will suffer at least partial LOFW events several times during plant life. The LOFW event is a heatup event [i.e., one in which the RCS temperature, pressure, and pressurizer (PZR) level increase in response to the transient] and represents the most general demand for the AFW system, that is, to merely provide flow to the SGs for heat removal when the normal feedwater supply is not available.

Total or partial LOFW can be initiated by any one of several circumstances, including main feedwater pump trip, main feedwater control valve closure, main feedwater isolation valve (FWIV) closure, and a host of other events. (In turn, these LOFW initiators can occur as the result of a multitude of causes, such as blown fuses, solenoid valve failure, main feedwater pump motor or turbine failure, etc.).

Charts showing typical accident analysis trends of RCS and secondary pressure following LOFW are presented in Figs. 2.5 and 2.6. These parameters are shown because certain key conditions can be readily seen from their curves. Following LOFW, SG levels drop, and RCS temperature and pressure begin to increase. Reactor trip could occur on any one of a number of trip signals, such as steam/feed flow mismatch, low SG level, high PZR pressure, etc. For total LOFW events, reactor trip would be expected to occur in short order (<1 min). Following the reactor trip, RCS temperature and pressure would initially drop but then gradually start to increase because of loss of forced RCS coolant flow (assumed to occur at the time of reactor trip). The AFW system is neither designed to

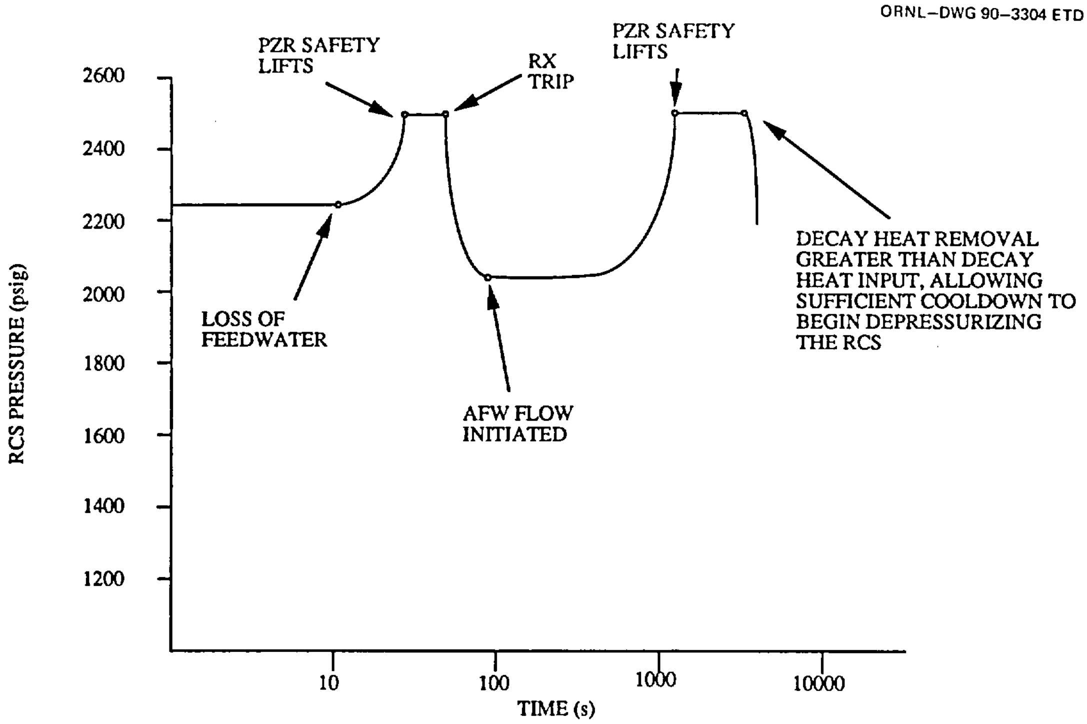

Fig. 2.5. RCS pressure response to loss of feedwater.

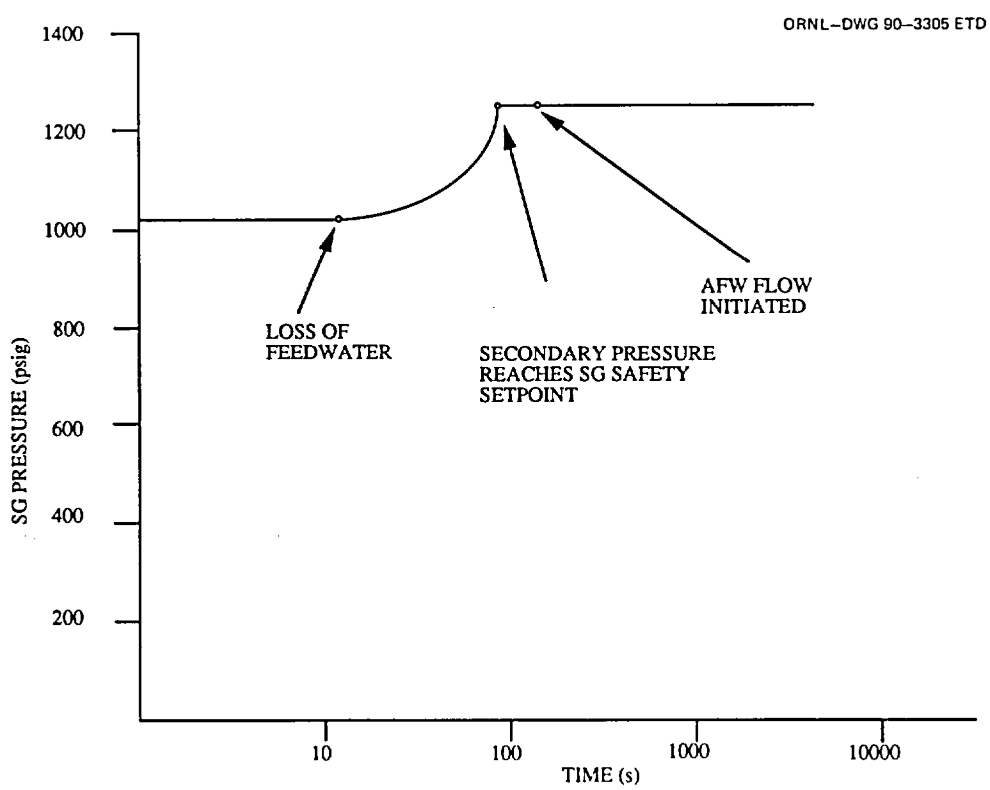

Fig. 2.6. SG pressure following loss of feedwater.

prevent reactor trip nor to prevent the initial heatup response that occurs before the trip; rather, it serves to mitigate the longer term posttrip heatup.

Following the reactor trip and the associated initial cooldown/depressurization, the RCS pressure increases to the point where the PZR safeties again lift to limit pressure. Secondary pressure increases to reach MSSV setpoint pressure. Both hot- and cold-leg temperatures increase because of loss of forced flow. Natural circulation flow develops because of the hot-leg/cold-leg temperature differential created by the SGs. Primary to secondary temperature differential may reach 30 to 40°F. Ultimately, as decay heat input decreases, even a single AFW pump can deliver adequate flow to allow heat removal to equal and then exceed decay heat input. Under the most limiting conditions (from a safety analysis standpoint) where no credit for control functions or for operator intervention is taken and assuming a limiting single failure, it can be 10 to 30 min following the reactor trip before heat input/heat removal equilibrium is reached. After this point, the RCS could be maintained at roughly Hot Standby conditions (although at an elevated temperature because of natural circulation vice forced circulation conditions), using only AFW and the MSSVs. Cooldown can be effected by use of SG power-operated relief valves or atmospheric dump valves.

2.3.5.2 Main feed line break

The response of the plant to an MFLB can vary considerably, depending on a number of factors, particularly the SG design and the location of the break. If the break occurs upstream of an FWIV or main feedwater isolation check valve, and those components function properly, the plant response will not be considerably different than that for a LOFW event. If the break occurs downstream of an FWIV, plant response can range from that associated with a substantial cooldown to the most severe analyzed heatup event.

If the main feedwater nozzle is located in a position such that a break in the line would result in the portion of the SG above the operating water level being exposed, the plant response will be a rapid cooldown and will appear similar to, though not quite as severe as the response to an MSLB. On the other hand, if the nozzle connection is such that the liquid portion of the SG is exposed, the plant response will differ substantially. The latter type event will be discussed here.

Figures 2.7 and 2.8 provide an indication of the response of RCS and SG pressure following a liquid portion feedline break. Level in the affected SG is lost fairly rapidly, resulting in a reactor and turbine trip. Secondary pressure rises quickly following the turbine trip. At the same time, the broken feedline is a source of depressurization for all SGs, resulting in a rapid turnaround of the pressure spike. Pressure in all SGs continues to drop rapidly until a main steam isolation signal (MSIS) occurs. Following the MSIS, the SGs are decoupled, and the faulted SG is readily identifiable.

The feedline break both prevents or minimizes feedwater flow reaching the SGs as well as drains the water from the affected SG, thereby reducing the inventory that is available for heat removal (although some heat is removed by the water that is blowing out the break, it is primarily sensible heat and represents a small fraction of the potential heat removal associated with the heat of vaporization).

From the perspective of the AFW system, the main feature associated with the MFLB event that is different from the LOFW event is that one SG is totally depressurized. The early plant response is somewhat similar to a steam line break (cooldown); but following the MSIS and the decoupling of the SGs, the event becomes a heatup transient similar to the loss of feedwater transient, with the exception that one less SG is available for heat removal. Also, note that unless automatic or manual control takes action to minimize or isolate flow to the faulted SG, very little AFW flow may actually reach the intact SGs, because flow would preferentially go to the low-pressure SG.

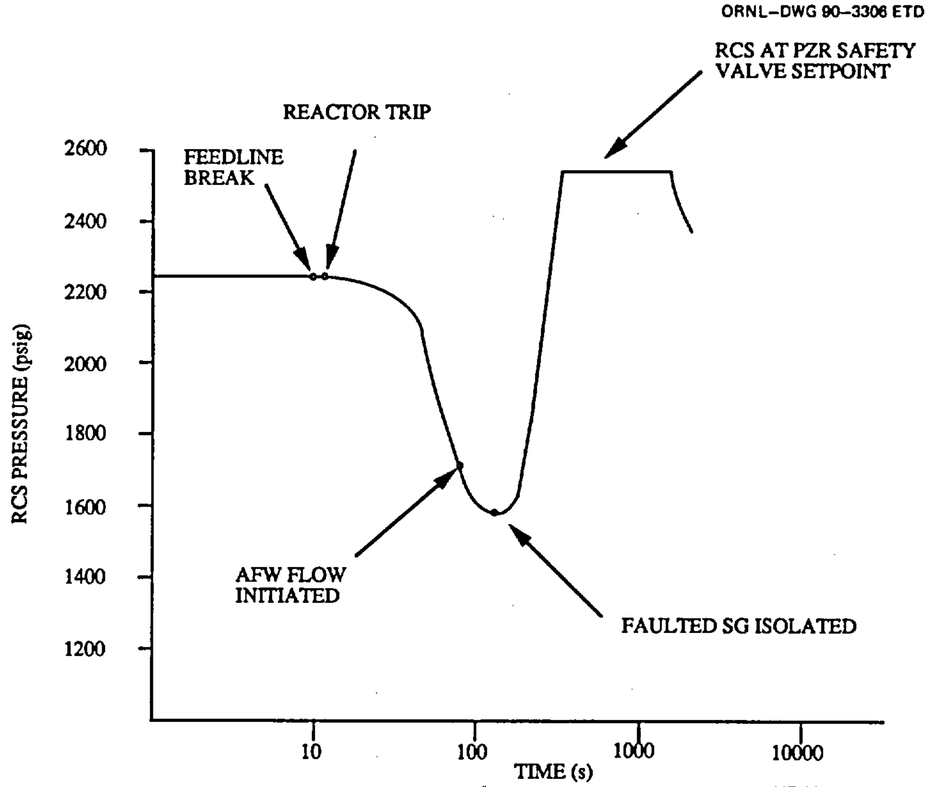

Fig. 2.7. RCS pressure response to feedline break.

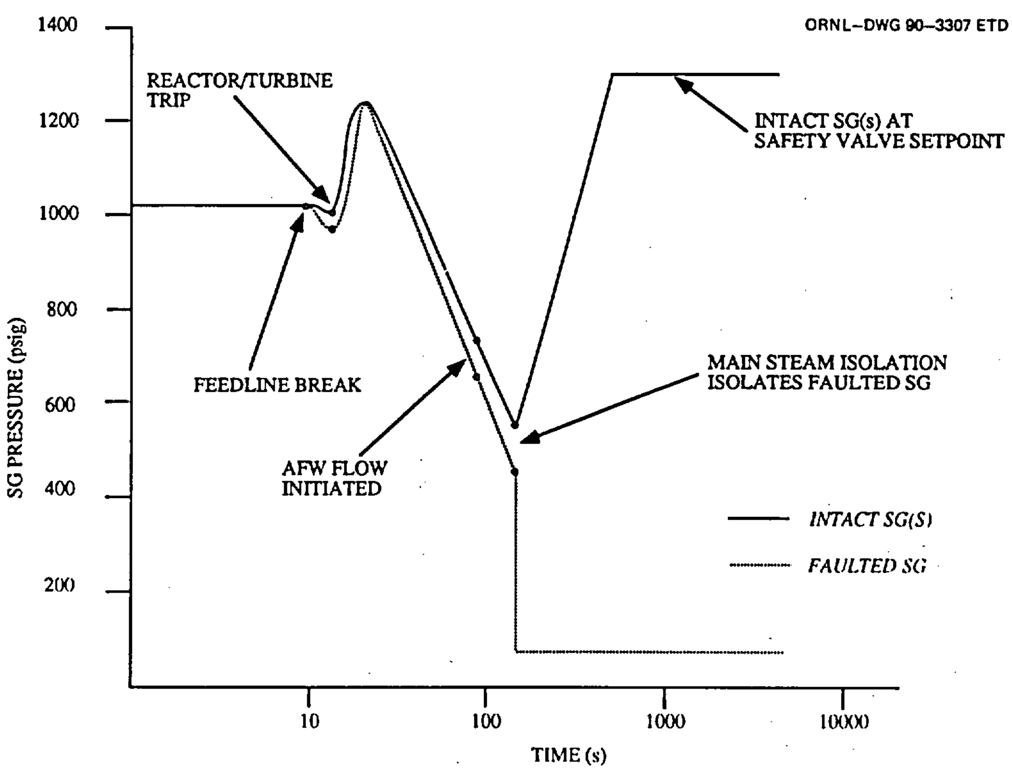

Fig. 2.8. SG pressure following feedline break.

As a result, various combinations of design features and operator actions are employed to ensure that the intact SGs can be fed following an MFLB. Some plants employ an automatic isolation scheme in which a faulted SG is sensed by process instrumentation and automatically isolated by means of AFW discharge valves. Some other plants rely, at least in part, on flow-limiting devices, such as cavitating venturis, to prevent an excessive amount of flow going to a faulted line (thereby robbing the intact SGs of feed). Other plants depend on operator action to detect and isolate a faulted SG.

2.3.5.3 Main steam line break

The MSLB is a design basis accident that creates a substantially different plant response than LOFW or MFLB. The MSLB causes a rapid cooldown, depressurization, and contraction of the RCS. Using the most limiting assumptions associated with design basis accident analyses, an MSLB may create a sufficient cooldown to cause a return to criticality, even after the reactor is tripped (because of a high negative moderator temperature coefficient). While not required during the early phases of an MSLB, because the break itself causes a substantial cooldown of the RCS, the AFW system, for most plant designs, would be automatically initiated by conditions resulting from the MSLB. Because any flow delivered to the faulted SG would serve to enhance the cooldown, termination of the flow is necessary. Also, if an MSLB were to occur inside containment, a substantial increase in containment temperature and pressure could occur. Any AFW flow delivered to the faulted SG would serve to magnify the temperature and pressure increase. As in the case of the MFLB, the various combinations of design features and operator actions are required to terminate flow to the faulted SG, although in this case, the need to terminate flow is driven more by the need to avoid excessive cooldown and steam release to containment than by the need to ensure that adequate flow is delivered to intact SGs.

3. REFERENCE PLANT DETAILED DESIGN

A cooperating utility allowed ORNL to review the details of the AFW design at an operating plant, along with associated operating, surveillance, and maintenance procedures. Further reference to this plant will be as "Plant A." The design of the Plant A AFW system will be discussed in Sect. 3.1; Sect. 3.2 provides additional information on Plant A procedural practices.

A simplified system flow diagram of the Plant A AFW system is provided in Fig. 3.1. The design requirements and actual design features of each of the major system components will be discussed in detail. The major configuration and design features of the system are

1. two motor-driven pumps, each capable of delivering flow to two SGs;
2. one turbine-driven pump, capable of delivering flow to all four SGs;
3. AFW discharge lines that connect with the main feed headers;
4. steam supply to the AFW turbine from either SG A or D; and
5. the normal supply of water from the CST, with ESW acting as a backup source.

There are several AFW automatic start signals. The motor-driven pumps (MDPs) start on

1. safety injection,
2. low-low level in one SG,
3. trip of either main feed pump at ≥80% power,
4. trip of both main feed pumps (at any power), and
5. station blackout (SB) signal.

The turbine-driven pump (TDP) starts on the same signals, except that low-low level in two SGs must exist for TDP start.

In addition to the pumps starting automatically, other AFW system features are automatically actuated. These will be discussed in detail for each of the specific components.

3.1 COMPONENT DESIGN FUNCTIONS, CONTROLS, AND INDICATION

3.1.1 Pump Suction Check Valves: C-3,* -4, and -5

3.1.1.1 Component Function and Design Features

The SCV opens on pump start to allow water from the CST to reach the pump suction. If the CST is depleted or for other reason a low suction pressure condition exists, the motor-operated ESW to AFW pump suction isolation valves open to admit water to the pump suction. When this occurs, the pump SCV closes to prevent backflow of ESW to the CST.

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*The component and procedure references used in this report are not the actual references used at Plant A. The references were modified in order to maintain confidentiality of the plant. However, the report is internally consistent in use of component and procedure references.

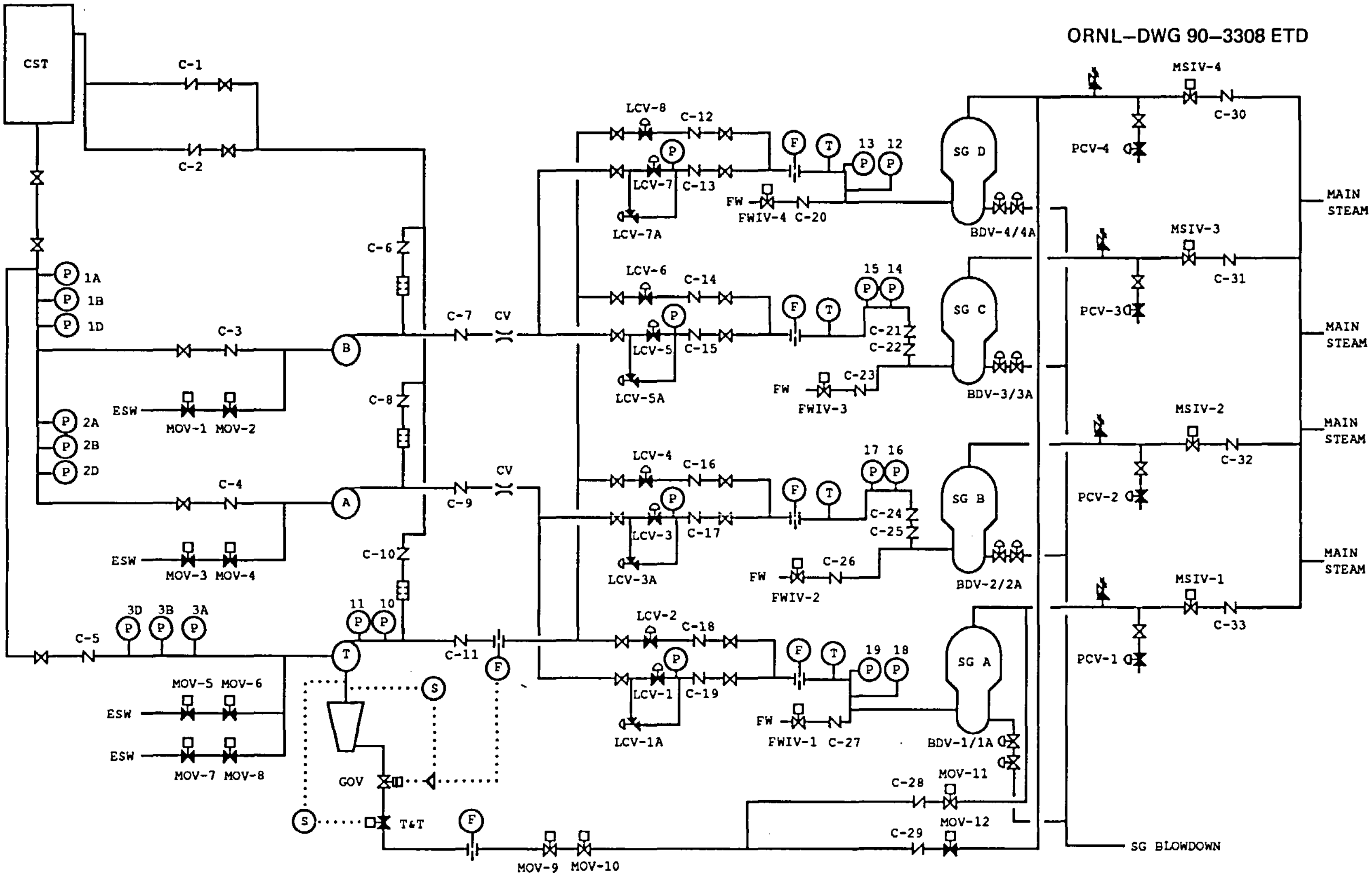

Fig. 3.1. Plant A auxiliary feedwater system.

The MDP SCVs are 8-in. swing check valves. The TDP SCV is a 10-in. swing check valve.

The general arrangement of the pump SCVs, including approximate distances from the nearest upstream elbow, are shown in Fig. 3.2. Note that there are 3 to 4 nominal pipe diameters between the elbow and the SCVs for the MDPs, while approximately one pipe diameter is between the elbow and the SCV for the TDP.

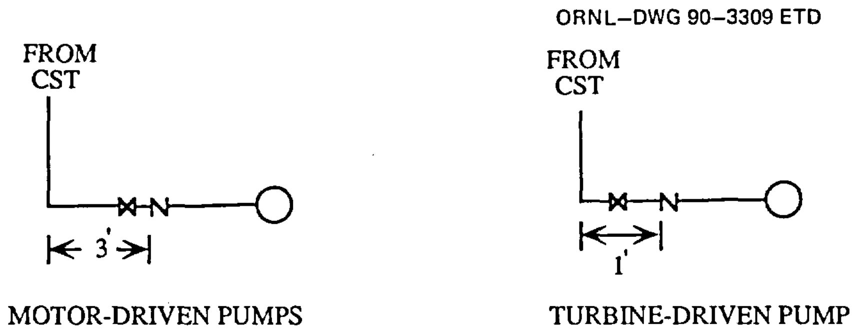

Fig. 3.2. Pump suction check valves configuration.

Under the design basis flow conditions of 465 gal/min for the MDPs and 920 gal/min for the TDP, the average approach velocities to the SCVs are ~3 and 4 ft/s, respectively. Under test alignment conditions where the pumps are on recirculation flow only, the velocities for both type pumps' SCVs are $<^1/_4$ ft/s. During startup/shutdown support, when the MDPs are run on a continuous basis, the MDP SCVs would see varying flow conditions, with the bulk of the time on recirculation only, but occasional "batching" flow rates of 165 gal/min, which would correspond to a velocity of ~1 ft/s.

3.1.2 Emergency Service Water to Motor-Driven Pump Suction Isolation Valves: MOV-1, -2, -3, and -4

3.1.2.1 Component Function and Design Features

ESW is the safety-grade supply of water for the AFW pumps; the CST is the normal supply source, but is nonsafety, nonseismic class. The switchover must occur quickly enough so that the pumps are not damaged or air bound because of loss of required suction head. At the same time, inadvertent switchovers should be avoided to prevent the introduction of lake water into the AFW system.

The ESW supply valves to the MDPs are normally closed 8-in. gate valves with 480-V ac motor operators (LIMITORQUE SMB-000). The permissives required for the valves to open are (1) low suction pressure sensed by 2/3 pressure switches in the pump suction header, and (2) the associated pump is running. The pump running permissive is provided by pump breaker auxiliary contacts (52S/a).

The suction pressure switches for each of the MDPs are *upstream* of the manual suction isolation valves (locked open valves) and the SCV. A main control board alarm annunciates if any suction pressure switch is "made." No time delay is associated with the alarm. The relays that energize on the 2/3 low suction pressure logic have a built-in 4-s time delay before they provide their part of the permissive to open the valves.

The open coil for the valve motor is deenergized by limit switch (no torque switch in the open coil circuit). The close coil circuit includes a torque switch that is bypassed by a limit switch except for the final 2 to 3% of stroke. Thermal overload heaters for the valves have been removed and replaced with jumpers.

Because there are few or no occasions when significant flow is delivered through the piping sections between the upstream isolation valves and the ESW headers, the potential exists for accumulation of Asiatic Clams in the stagnant piping. To combat this potential, the plant provides for chlorination (0.2 to 2.0 ppm) of the piping sections whenever the intake temperature exceeds 60°F. Chlorination on a year-round basis is also required for microbiologically induced corrosion control, if chlorine discharge limits are not exceeded.

3.1.2.2 Controls

1. Main control board (MCB) handswitches (HS-1/2A and HS-3/4A) with "OPEN," "CLOSE," and "AUTO" positions (the CLOSE and OPEN positions spring return to AUTO). Note that MOV-1 and -2 are controlled from a single handswitch, as are MOV-3 and -4.
2. Motor control center (MCC) handswitches (HS-1/2C and HS-3/4C) with "OPEN," "CLOSE," and "AUTO" positions (the CLOSE and OPEN positions spring return to AUTO).
3. Transfer switches at the MCCs with "AUX" and "NOR" positions (XS-3/4 and XS-1/2). The MCB controls are enabled in "NOR," and the MCC controls are enabled in "AUX." The automatic transfer circuit is enabled with the transfer switches in either position.
4. Local control panel with "OPEN," "CLOSE," and "STOP" pushbuttons. These controls are not affected by the transfer switch position; however, the STOP pushbutton provides contacts (which are "made" as long as the pushbutton is not depressed) that enable the valve open and close coil seal-in circuits for MCB or MCC control.

3.1.2.3 Indication/Alarms

1. Valve position indicating lights at MCB, MCCs, and local control panel.
2. MCB annunciation of low suction pressure condition (1/3 logic). Note that the alarm that is lit is labeled "PS-3A COND STG TANK HDR TO AUX FWPS PRESS LOW." The alarm actually comes in if a low suction pressure condition is sensed by 2/3 instruments for any of the three pumps, including the PS-1, -2, or -3 set.
3. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator.
4. Status monitoring system (which provides to operators, via control room monitor, indication of off-normal conditions for a large number of plant components) inputs: Valve open; No power to valve operator.

3.1.3 Emergency Service Water to Turbine-Driven Pump Suction Isolation Valves: MOV-5, -6, -7, and -8

3.1.3.1 Component Function and Design Feature

The ESW supply valves to the TDP are normally closed 10-in. gate valves with 480-V ac motor operators (LIMITORQUE SMB-00). The automatic open permissives are (1) low suction pressure sensed by 2/3 pressure switches in the pump suction header, and (2) TDP starting.

The pump starting portion of the permissive originates from a T&T valve stem limit switch that closes when the T&T valve is half-open. If a low suction pressure condition exists after the turbine trip and throttle valve has reached the midpoint of its open stroke, a 5.5-s time delay relay (AAA) energizes. Energization of the AAA relay, in turn, closes contacts that cause two other relays (BBB and AAB) to energize. (Note that the AAB relay has another 5.5-s time delay before energization.)

The BBB relay causes contacts in the MOV-7 and -8 open coils to close, resulting in the valves starting to stroke open. If the low suction pressure condition clears in the 5.5 s between energization of the BBB relay and the energization of the AAB relay, all the relays will deenergize, MOV-7 and -8 will continue to open (because of a seal-in for the open coil), and MOV-5 and -6 will not be affected.

If, however, the low suction pressure condition has not cleared within the 5.5 s, the AAB relay will energize, resulting in contact closure that energizes relay CCC, which in turn causes contacts in the MOV-5 and -6 open coils to close, and the valves will then stroke open. In addition, the AAB relay closes a contact that energizes relay BBA, which closes contacts in the MOV-7 and -8 *close* coil circuit. When the MOV-7 and -8 valves have fully opened, their open coils deenergize, their close coils energize, and the valves stroke back to the shut position. (A similar automatic closure circuit does not exist for MOV-5 and -6.)

The intended result of the sequence is that if the low suction pressure condition does not clear within the 5.5-s period following the start of the opening of MOV-7 and -8, the MOV-5 and -6 valves will open and the MOV-7 and -8 valves will stroke back to the shut position, thereby avoiding cross-train connection while providing the safety grade suction source to the TDP.

The open coil for each valve motor is deenergized by a limit switch (no torque switch in the open coil circuit). The close coil circuit includes a torque switch that is bypassed by a limit switch except for the final 2 to 3% of stroke. Thermal overload heaters for the valves have been removed and replaced with jumpers.

3.1.3.2 Controls

1. MCB handswitches (HS-7/8A and HS-5/6A) with "OPEN," "CLOSE," and "AUTO" positions (the CLOSE and OPEN positions spring return to AUTO). Note that MOV-5 and -6 are controlled from a single handswitch, as are MOV-7 and -8.
2. MCC handswitches (HS-7/8C and HS-5/6C) with "OPEN," "CLOSE," and "AUTO" positions (the CLOSE and OPEN positions spring return to AUTO).
3. Transfer switches at the MCCs with "AUX" and "NOR" positions (XS-7/8 and XS-5/6). The MCB controls are enabled in "NOR," and the MCC controls are enabled in "AUX." The automatic transfer circuit is enabled with the transfer switches in either position.
4. Local control panel with "OPEN," "CLOSE," and "STOP" pushbuttons. These controls are not affected by the transfer switch position; however, the STOP pushbutton provides contacts (which are "made" as long as the pushbutton is not depressed) that enable the valve open and close coil seal-in circuits for MCB or MCC control.

3.1.3.3 Indication/Alarms

1. Valve position indicating lights at MCB, MCCs, and local control panel.
2. MCB annunciation of low suction pressure condition (1/3 logic). Note that the alarm that is lit is labeled "PS-3A COND STG TANK HDR TO AUX FWPS PRESS LOW." The alarm actually comes in if a low suction pressure condition is sensed by 2/3 instruments for any of the three pumps, including the PS-1, -2, or -3 set.
3. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator.
4. Status monitoring system inputs: valve open; no power to valve operator.

3.1.4 Motor-Driven AFW Pumps

3.1.4.1 Component Function and Design Features

Each MDP must start in response to automatic or manual start signals and provide a flow rate of ≥440 gal/min to two SGs with the SGs at 1085 psig (lowest safety valve setpoint pressure plus 2% accumulation). The flow requirement is based upon accident analysis assumptions.

The MDPs are Ingersoll-Rand nine-stage (3HMTA-9) pumps that are provided with three-phase, 6600-V, 500-hp motors.

The motor breaker closes on the following signals:

1. SI,*
2. low-low level in one SG,*
3. trip of either main feed pump at ≥80% power,
4. trip of both main feed pumps (at any power),
5. SB,*
6. manual (from the MCB, the pump breaker cubicle, or a local panel), and
7. anticipated transient without scram mitigating system actuation circuit (AMSAC).

If proper supply bus voltage is available when an automatic start signal occurs, the AFW pumps will be immediately started. A sequencing time delay is built into the SB start signal, which is actually not initiated by an SB (total loss of on-site ac power), but rather by a temporary emergency bus undervoltage condition (commonly referred to as loss of offsite power). For the pumps to start, the undervoltage condition must first exist (for at least 5 s), and then clear (when the diesel generator output breaker is closed). There is a time delay of ~30 s from undervoltage condition initiation until pump starting in the SB portion of the AFW pump starting circuit. The 30 s consists of ~10 s for the associated emergency diesel-generator to achieve rated speed and reenergize the emergency bus plus a 20-s time delay in the AFW pump breaker closing circuit as a part of diesel load sequencing. Should an SI signal occur during the 20 s associated with the AFW timers, the timing sequence will be reinitiated (the other automatic start signals, such as low-low SG level, do not affect load sequencing).

Note that either an SI or SB start signal blocks the signals related to low-low SG level and main feed pump trip. If control has been switched from the MCB to auxiliary control (6.9-kV switchgear), all automatic start signals, except for SB, are disabled.

If an AFW pump is running (because of either a manual or automatic start signal) at the time that an undervoltage condition occurs, the pump is tripped, and then subsequently automatically sequenced onto the emergency bus, as described previously. While an undervoltage condition exists on the emergency bus, manual pump start is blocked; however, once the bus is reenergized, manual start capability is restored.

The pump motors are provided with electrical fault protection by time and instantaneous overcurrent relays, as well as neutral overcurrent relays.

Minimum flow protection is provided by a recirculation line with a flow-restricting orifice. The design flow through the recirculation line is 25 gal/min (per pump). Reference flows (for pump in-service testing) are 34.2 and 31.5 gal/min for the A and B pumps, respectively.

*Safety-related start signal.

Design runout protection for each pump is provided by a cavitating venturi. The venturi is sized to limit flow through it to 650 gal/min (limiting total pump flow to ~675 gal/min, including recirculation flow).

Based on pump and system head curves (from design calculations), the MDPs are capable of delivering 462 gal/min to the SGs with the SGs at 1085 psig (note that the 462 gal/min to the SGs includes an allowance for 25-gal/min recirculation flow). Thus, the pumps have a 5% nominal design flow margin relative to safety analysis requirements.

Pump net positive suction head (NPSH) protection is offered by an automatic switchover from the normal suction source, the CST, which is a nonsafety, nonseismic source, to the safety-grade, seismically qualified ESW system. The automatic transfer scheme requires that a low suction pressure condition (2 psig) be detected by 2/3 pressure switches, and that the associated pump be running (as indicated by the closure of pump breaker auxiliary contacts 52S/a). A 4-s time delay is built into the automatic transfer circuit to avoid spurious transfer. The valves that are automatically opened for the suction transfer are 480-V ac motor operated valves that are powered off of the same train as the associated pump.

The pump motor includes auxiliary breaker contacts that provide inputs to various indication and control functions:

1. Each of the associated MDP level control and bypass level control valve circuits have two sets of contacts that are affected. One set opens on pump start (52S/b) to deenergize the level control valve solenoid, thereby allowing the valve to modulate; the other set closes on pump start (52S/a) to provide a portion of the logic necessary to accomplish the automatic transfer from level control valve control to bypass level control valve control (the other portion of the logic is made up by a pressure switch).
2. An auxiliary contact (52S/b) opens on pump start to provide a closure signal to the SG BDIVs.
3. Each alternate suction supply isolation valve open circuit has a pump motor auxiliary contact that closes on pump start (52S/a) to provide a portion of the logic necessary to accomplish the automatic opening of the valve (the other portion of the logic is made up by operation of 2/3 of the associated suction pressure switches).
4. An auxiliary contact opens on pump start (52S/b) to deenergize a relay (1X) that, in turn, blocks a continuing closure signal to the breaker.
5. Pump status lights and monitoring system inputs receive inputs from other auxiliary contacts.

3.1.4.2 Controls

The MCB control switches for the AFW MDPs have the following positions:

1. START (with spring return to AUTO),
2. STOP (with spring return to AUTO),
3. AUTO, and
4. PULL TO LOCK.

Pump start and stop controls are also provided at the pump motor switchgear cubicle and at a local control panel. A transfer switch is provided at the switchgear cubicle to allow transfer from MCB control to auxiliary control. With the transfer switch in the "NORMAL" position, the pump control at the MCB is enabled; in the "AUXILIARY" position, control at the pump switchgear cubicle is enabled. The local control panel controls are always enabled, regardless of transfer switch position.

3.1.4.3 Indication/Alarms

1. Motor ammeters located at MCB and at motor switchgear cubicle
2. Overcurrent annunciator
3. Pump motor breaker indicating lights at MCB and motor switchgear cubicle: Green – open (pump off) and Red – breaker closed (pump running)
4. White light at MCB to indicate either an overcurrent condition or motor starting lockout logic failure
5. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
6. Pump discharge pressure
7. Individual SG header flow (note that the flow being monitored includes flow from the TDP, but is labeled as "MOTOR AFWP FLOW")
8. Status monitoring system inputs: pump "RUNNING," pump handswitch in "PULL TO LOCK," pump "PWR OFF" (indicates no control power to pump breaker or breaker in racked out position)

3.1.5 Turbine-Driven AFW Pump

3.1.5.1 Component Function and Design Features

The TDP provides a diverse means of delivering AFW to the SGs with no reliance on ac power (with the exception of 120-V ac instrument busses that are energized by dc busses through an inverter). The turbine is started by opening of the T&T valve, which occurs in response to several automatic signals:

1. SI,*
2. SB signal (from two relays on either Train A or Train B),*
3. low-low SG level in 2/4 SGs,*
4. trip of both main feed pumps at any power level,
5. trip of either main feed pump at >80% power, and
6. AMSAC.

The TDP is an Ingersoll-Rand five-stage (3HMTA-5) pump that is driven by a noncondensing turbine (Terry Turbine, type GS-2) at a nominal operating speed of 3970 rpm. Included as an integral part of the turbine drive are the dc motor-operated T&T valve, a hydraulic governor valve (GV), and associated governor control circuitry.

The T&T valve can be used, as its name implies, for both throttling and overspeed protection purposes. However, it is not normally used for throttling.

The T&T valve automatically closes for the following conditions:

1. electronic overspeed trip (4300 rpm),
2. mechanical overspeed trip (4900 rpm), and
3. failure of the TDP to develop 100 psig discharge pressure within 60 s after the T&T valve opens. This closure is provided to allow automatic transfer of the steam supply source from SG A (normal source) to SG D (alternate source).

The overspeed tripping not only protects the turbine itself, but provides inherent pump runout and discharge piping overpressurization protection as well. Both the electronic and mechanical overspeed trips are accomplished by unlatching the T&T valve

*Safety-related start signal.

from its operator. In the case of the electronic overspeed trip, the motor operator automatically drives to the closed position following the trip and relatches the valve. If the open signal is still present, the valve will automatically reopen. For the mechanical overspeed trip, the valve motor will also automatically drive shut following the trip, but local manual reset of the mechanical trip lever is required before the valve can be reopened. Both the electronic and the mechanical overspeed trips are annunciated in the main control room.

If the TDP fails to develop 100 psig discharge pressure within 60 s after the T&T valve begins to open, an automatic transfer of steam supply source occurs. The sequence involves driving the T&T valve shut, closing the normal steam supply valve (MOV-11), opening the alternate steam supply valve (MOV-12), and then reopening the T&T valve. This entire sequence is accomplished automatically. See the discussion for MOV-11 and -12 for further details of the automatic steam supply transfer.

The thermal overload switches for the T&T valve motor operator are bypassed if any automatic open signal is present (note that the switches are bypassed in both the open and close direction, as long as one of the automatic open signals is present).

The torque switch in the open direction is bypassed for the full stroke for all automatic and manual open strokes. The torque switch in the closed direction is bypassed except for the final 2 to 3% of stroke.

T&T valve stem limit switches provide control and indication inputs to several support functions associated with the AFW system:

1. enable the ramping function of the GV control circuit,
2. provide a start signal to the TDP room ventilation fan,
3. start the 60-s timer for the automatic steam supply transfer circuit ,
4. enable the automatic closure feature for the valve's motor operator in the event of an overspeed trip,
5. provide close signal to the SG BDIVs,
6. provide a permissive signal to allow opening of the ESW isolation valves in the event of low suction pressure, and
7. provide local and MCB indication of valve position.

Turbine speed is normally controlled by the turbine GV, which is a 3-in. hydraulically operated plug valve with a Woodward EG governor (Fig. 3.3 provides a simplified schematic of the GV control configuration). Varying hydraulic pressure is exerted on the GV remote servo piston by the governor's hydraulic actuator. Oil pressure for the actuator is developed by an internal gear-driven pump, which is driven off of the turbine shaft (the turbine lube oil pump, which is also shaft driven, supplies oil to the governor actuator). The oil pressure delivered by the actuator to the remote servo is controlled by an electrical input signal to the actuator that comes from the governor's electric control box.

During steady state operation of the turbine, three summed signals make up the net signal delivered to the actuator: (1) a motor-operated potentiometer provides a minimum control setpoint (positive input), (2) a ramp generator/signal converter (RGSC) provides a positive input signal that is based upon pump discharge flow, and (3) a negative feedback signal from a turbine speed sensor. The RGSC also provides a mechanism for controlled ascension from idle to normal operating speed by varying its portion of the input. The initial signal output is an idle speed signal. As the T&T valve opens, a limit switch initiates a ramp signal that gradually increases the RGSC output over roughly a 15-s period, allowing the turbine speed to increase accordingly until it can be controlled by the steady state signals (see Fig. 3.4).

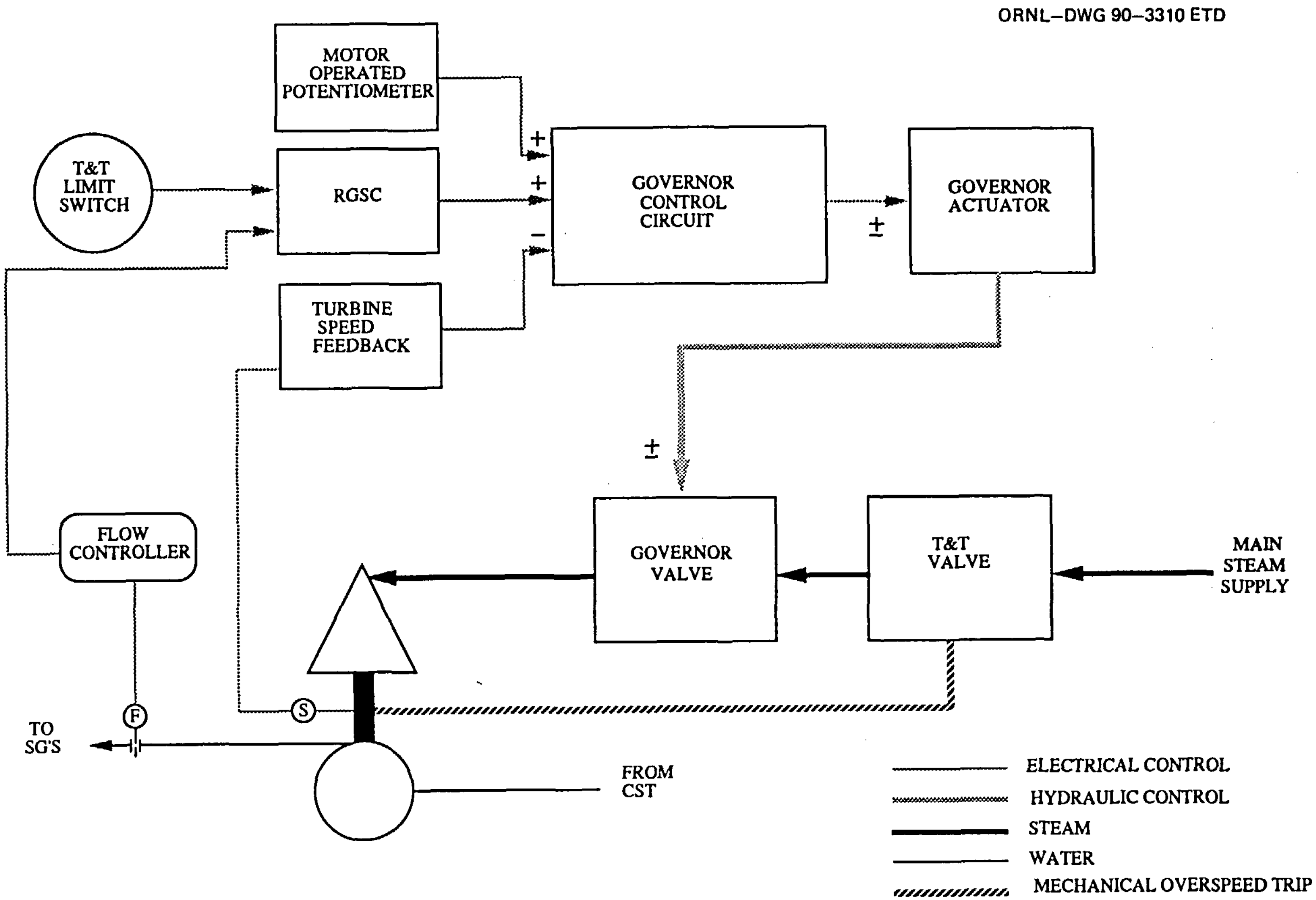

Fig. 3.3. AFW turbine speed control circuit.

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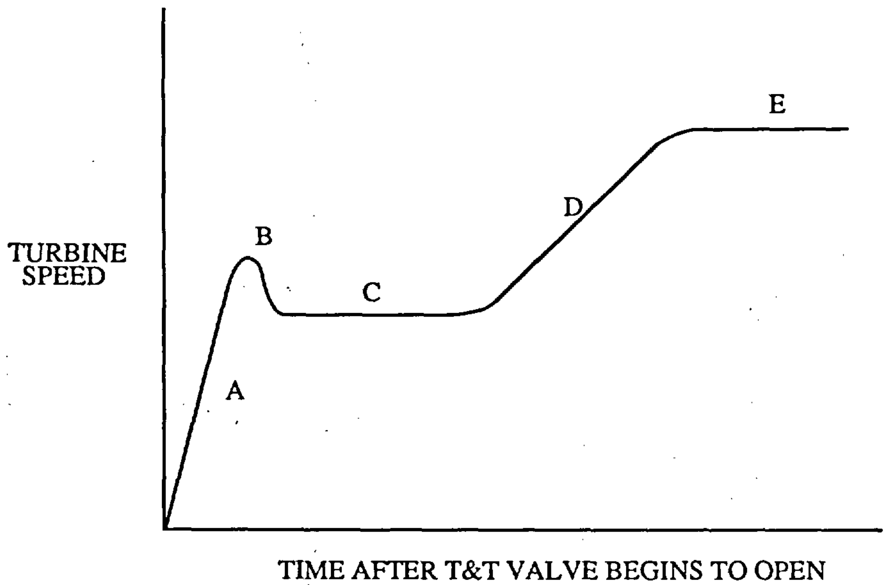

A. Initial acceleration as T&T valve admits steam

B. Turbine governor oil pressure builds up and is able to drive governor valve in closed direction

C. Turbine at "idle" speed

D. Turbine speed accelerating in conjunction with ramp signal

E. Turbine achieves normal operating speed

Fig. 3.4. Turbine speed during startup.

The RGSC has an internal low signal selector that results in its output being based upon the lesser of the ramp signal or the flow signal, which is an input to the RGSC. Thus, during startup, the ramp signal increases to the point where it exceeds the flow-based signal, and from that point on, the three steady state signals noted above are controlling. The general process associated with turbine startup from standby to normal operating speed is explained below.

In standby conditions, the GV is normally held in the full-open position by springs in the servopiston/GV linkage. There is no hydraulic pressure, since the source of hydraulic pressure originates from the oil pump, which is driven off of the turbine shaft. When the trip and throttle (T&T) valve begins opening, the turbine begins to roll, and the shaft driven oil pump is able to develop discharge pressure. Because the GV repositioning from full-open to the control position depends upon the development of the discharge pressure, there is an associated initial lag in speed control development. This lag can be seen in Fig. 3.4. Initially turbine speed increases rapidly until the GV actuator develops pressure and starts to close the valve in response to the low positive demand signal associated with the idle speed signal in conjunction with the rapidly increasing negative feedback from turbine speed (Section A of Fig. 3.4). As the GV closes, the speed increase is halted, and speed is reduced to the idle speed (Section C). As the T&T valve continues to open, the ramp is initiated by a stem-actuated limit switch, and the RGSC output signal gradually increases (Section D) to the point where the steady state speed associated with balanced flow and speed signals is reached (Section E).

Normally, turbine speed will be controlled automatically, as described above, following an automatic turbine start. However, turbine speed, and hence total pump flow can be manually controlled by use of a controller at the MCB. For the controller to be used in manual following an automatic start, the MCB control switch must initially be transferred to an "Accident Reset" position and then pulled to its manual position. It can then be turned to either increase or decrease the signal being sent from the flow controller to the turbine speed control circuit.

An exception to the switch to manual control occurs in the case of automatic pump start upon the loss of either main feed pump with the plant at >80% power. In this case, the TDP flow control cannot be put in manual (the "Accident Reset" relay is nulled by an open contact in the controller input). However, the open contacts reclose once plant power has decreased to <75%, restoring the "Accident Reset" capability. Note that the 80% and 75% power-related actions depend upon nonsafety-related equipment (such as nonsafety pressure sensors, electrical contacts, and power supply).

The pump design nominal capacity is 920 gal/min (including 40 gal/min recirc), 2600-ft total developed head with the turbine operating at 3970 rpm and the SGs at 1085 psig. As pressure in the SGs is reduced, the TDP capability decreases until the nominal design capacity is 525 gal/min, 325-ft total developed head with the steam supply source at 125 psig, and turbine speed at 2200 rpm. The flows cited do not include minimum recirculation line flow, which is nominally 40 gal/min. Note that manual speed control is required as steam supply pressure is reduced.

Pump NPSH protection is offered by an automatic switchover from the normal suction source, the CST, which is a nonsafety, nonseismic source, to the safety-grade, seismically qualified ESW system. The automatic transfer scheme requires that a low suction pressure condition exist (13.9 psig on 2/3 pressure switches), and that the T&T valve has reached at least the half-open point of its stroke . A 5.5-s time delay is built into the automatic transfer circuit to avoid spurious transfer. See the discussion for MOV-5, -6, -7, and -8 for further details of the automatic suction source transfer.

3.1.5.2 Controls

1. MCB valve control handswitch with "CLOSE," "OPEN," and "NOR" (Normal), with a spring return to "NOR." With the switch in "NOR," this switch has no impact on the valve automatic function.
2. MCB valve trip pushbutton with "TRIP" and "NOR" (Normal) positions, with spring return to "NOR." Depressing the pushbutton has the same effect as an electronic overspeed trip.
3. MCB Controller for TDP speed/flow control with both Manual and Auto positions (i.e., in for Manual, out for Auto). In Manual, turbine speed (and hence pump flow) can be raised or lowered. Accident Reset positions are provided to allow resumption of manual control following an automatic start of the turbine.
4. Transfer switch located at a local control panel with "AUX" and "NOR" positions, which allows transfer of T&T valve control to local. Note that with the control transferred to local, all of the valve automatic open functions as well as the electronic overspeed trip are blocked.

5. Pushbuttons at local control panel to "OPEN," "CLOSE," and "TRIP" the T&T valve (these pushbuttons are only enabled if the transfer switch is in the "AUX" position).
6. Another local control pushbutton, labeled "STOP," to interrupt T&T valve stroking at any point in the open or close stroke. When this pushbutton is in the normal, released position, it provides contacts that must be "made" for any open or close strokes to occur.
7. Motor-operated potentiometer located near the TDP that allows some control over turbine speed. This control would normally only be used in setting the governor minimum control setpoint.

3.1.5.3 Indication/Alarms

1. T&T valve position indicating lights at MCB and local controls
2. Annunciator for electronic overspeed trip
3. Annunciator for mechanical overspeed trip
4. Status Monitoring System signal for T&T Valve open; no power to T&T Valve; no power to speed control (this would also indicate no power to automatic suction source transfer relays)
5. TDP flow controller MANUAL/AUTO indicating lights at MCB
6. TDP flow indication at MCB and at local controls
7. Reference minimum control speed (from motor operated potentiometer input to turbine speed control circuit) at MCB and at local controls
8. Turbine speed indication at MCB and at local controls
9. Indicating light at Auxiliary Control Room panel for the AMSAC test circuit

3.1.6 Pump Miniflow Check Valves: C-6, -8, and -10

3.1.6.1 Component Function and Design Features

The miniflow check valves (MCVs) are 1-$^1/_2$-in. swing check valves that open on pump start to allow a portion of the pump discharge flow to be recirculated to the CST. The check valves provide train separation for the three pump recirculation lines, which join to form a common recirculation header.

Nominal flow rates for the MDPs and TDPs are 25 and 40 gal/min, respectively, with flow being primarily limited by breakdown orifices in each recirculation line. At these flow rates, the average flow velocities are about 6 ft/s for C-6 and -8 and 9 ft/s for C-10.

Note that the flow rates provided by the minimum flow lines are substantially less than the continuous flow currently specified by the pump vendor for the pumps (e.g., the current specified continuous minimum flow rate for the MDPs is 170 gal/min). As is the case for AFW systems at most operating plants, the minimum flow rates allowed by the recirculation orifices are sufficient to prevent overheating, but not sufficient to provide protection against pump degradation from low-flow operation.

3.1.7 Common Miniflow Check Valves: C-1 and -2

3.1.7.1 Component Function and Design Features

The common miniflow check valves (CMCVs) are 3-in. swing check valves that must open on pump start to allow a portion of the pump discharge flow to be recirculated to the CST.

Under most AFW test or operating conditions, the CMCVs see extremely low flow rates, with average flow velocities of about 0.6 ft/s. Even under the maximum test conditions (associated with "full" stroking of the CMCVs), the flow velocities would be <5 ft/s.

3.1.8 Pump Discharge Check Valves: C-7, -9, and -11

3.1.8.1 Component Function and Design Features

The DCVs are 6-in. swing check valves that are normally closed in standby condition. The DCV opens on associated pump start to allow pump discharge flow to proceed through the flowpaths to the SGs. The DCV for a particular pump, along with an additional check valve in the pump discharge flowpath (level control valve check valve), prevents flow reversal from another pump in the event a pump fails to start. The DCVs also prevent, along with other check valves and the normally closed level control valves (LCVs), backleakage from main feedwater during normal operation.

The layout of the discharge check valves is shown in Fig. 3.5. At design flow rates (440 gal/min for the MDPs and 880 gal/min for the TDP), the average velocities at the check valves are ~5 ft/s for C-7 and -9 and 11 ft/s for C-11.

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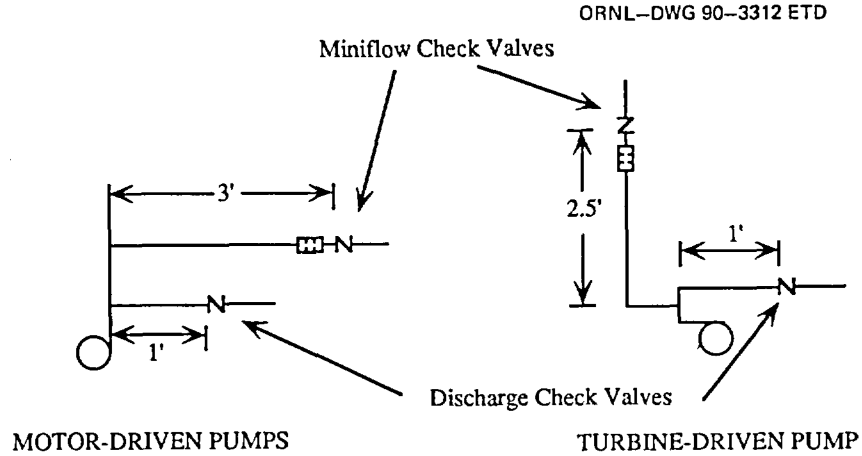

Fig. 3.5. Pump miniflow and discharge check valves configuration.

3.1.9 Motor-Driven AFW Pump Level Control Valves: LCV-1/1A,* -3/3A, -5/5A, and -7/7A

3.1.9.1 Component Function and Design Features

The motor-driven pump level control valves (MDLCVs) and the BMDLCVs are normally closed, with controls in "AUTO" in standby condition, and open/modulate following associated pump start. SG level of 33% is automatically maintained by the air-operated valves.

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*Note: Valves with the "A" suffix to the number will be referred to as BMDLCV (bypass MDLCV).

If a pressure of <400 psia downstream of the valves is sensed with the associated pump running, an automatic transfer from the MDLCVs to the BMDLCVs is initiated. The purpose of the transfer from the 4-in. MDLCVs to the 2-in. BMDLCVs is to prevent excessive pressure drop across the 4-in. valves.

In addition to responding automatically to allow flow to intact SGs following an AFW actuation signal, the operator must be able to regain manual control of the MDLCVs and BMDLCVs following certain design basis accidents (e.g., feedline or steamline breaks). This is necessary to ensure that intact SGs can be fed as well as limiting the extent of containment pressurization and RCS cooldown.

The normally closed MDLCVs fail open on loss of air or control signal power. On loss of solenoid power, the valves modulate based on control signal input. Associated pump breaker auxiliary contacts (52S/b) open when the pump starts and deenergize the MDLCV solenoids, allowing the valves to modulate.

The normally closed BMDLCVs fail closed on loss of air or solenoid power. If control signal is lost, the BMDLCVs will go full open (if solenoid energized) or full closed (if solenoid deenergized). The automatic transfer from the MDLCVs to the BMDLCVs occurs if a pressure of <400 psia downstream of the valves exists (low pressure condition must exist for 15 s to enable the automatic transfer).

SG level can be manually controlled after any accident signal by taking the valve's handswitch first to "Accident Reset," and then to "Manual" or "Manual Bypass." In "Manual," the MDLCV position can be manually controlled from the control room. In "Manual Bypass," the MDLCVs will be closed, but the BMDLCVs will modulate in response to manual adjustment from the control room.

An exception to the switch to manual control occurs in the case of automatic pump start on the loss of either main feed pump with the plant at >80% power. In this case, the MDLCVs cannot be put in manual (the "Accident Reset" relay is nulled by open contacts in the controller input); however, the switch to "Manual Bypass" can be made with the result of the MDLCV going closed and the BMDLCV responding to manual adjustment from the control room. In addition, the open contacts reclose once plant power has decreased to <75%, restoring the "Accident Reset" capability. Note that the 80% and 75% power-related actions depend upon nonsafety-related equipment (such as nonsafety pressure sensors, electrical contacts, and power supply).

3.1.9.2 Controls

1. MCB switches for the MDLCVs and BMDLCVs (HS-1A, -3A, -5A, and -7A) are dual-switch sets. The upper switch has the following positions: "MANUAL," "MANUAL BYPASS," and "AUTO (DEPRESS FOR ACC RESET)." The switch depression for accident reset has a spring return to "AUTO."
2. The lower switch, which is enabled when the upper switch is in "MANUAL" or "MANUAL BYPASS" only, has "RAMP OPEN" and "RAMP CLOSE" positions, with spring return to center.
3. Transfer switches for each valve set are located at the Auxiliary Control Panel (ACP). Transferring to the ACP has the same effect on the controller as an accident signal, because the controller will switch from manual to automatic level control.
4. A level-indicating controller (LIC-1, -3, -5, -7) is provided for each valve set at the ACP. It is via these controllers that the automatic level control setpoint is established.

3.1.9.3 Indication/Alarms

1. Valve position indicating lights (for both MDLCVs and BMDLCVs) at MCB
2. Valve controller MANUAL or AUTO indicating lights at MCB

3. Loop level indication at MCB
4. High and low SG level alarms at MCB
5. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
6. Status monitoring system input to indicate that solenoids are deenergized, allowing MDLCVs to modulate

3.1.10 Turbine-Driven Pump Level Control Valves: LCV-2, -4, -6, and -8

3.1.10.1 Component Function and Design Features

The TDLCVs, which are normally closed 3-in. globe valves with controls in "AUTO," open/modulate following pump start. An SG level of 33% is automatically maintained by the air-operated valves. Individual TDLCVs automatically close if a pipe break downstream of the pertinent valve is sensed. During normal operation, the TDLCVs, along with in-series check valves, prevent backleakage of main feedwater into the AFW.

The normally closed TDLCVs fail closed on loss of air or control signal power. An accumulator is provided to allow valve modulation in the event of loss of control air. On loss of solenoid power, the valves modulate based on control signal input. The TDLCV solenoids are deenergized when TDP discharge pressure, as sensed by pressure switches PS-10 (for LCV-6 and -8) and PS-11 (for LCV-2 and -4), reaches 100 psig.

To provide pipe break protection, two pressure switches are located downstream of each TDLCV (e.g., PS-18 and -19 for LCV-2). If either of the two pressure switches closes (setpoint = 100 psia), the associated TDLCVs solenoid will be energized, resulting in valve closure. Note that a 30-s time delay, beginning with initial solenoid deenergization, is built into the auto-closure circuit. If the TDLCV handswitches are in manual before an automatic pump start, the controllers will automatically transfer from manual to automatic. SG level can be manually controlled after any accident signal by taking the valve's handswitch first to "Accident Reset," and then to "Manual."

An exception to the switch to manual control occurs in the case of automatic pump start upon loss of either main feed pump with the plant at >80% power. In this case, the TDLCVs cannot be put in manual (the "Accident Reset" relay is nulled by open contacts in the controller input). However, once plant power has decreased to <75%, the open contacts reclose, allowing restoration of the "Accident Reset" function and the subsequent transfer to manual. Note that the 80% and 75% power-related actions depend on nonsafety-related equipment (such as nonsafety pressure sensors, electrical contacts, and power supply).

3.1.10.2 Controls

1. MCB switches for the TDLCVs (HS-2A, -4A, -6A, and -8A) are dual-switch sets. The upper switch has the following positions: "MANUAL" and "AUTO (DEPRESS FOR ACC RESET)." The switch depression for accident reset has a spring return to "AUTO."
2. The lower switch, which is enabled when the upper switch is in "MANUAL" only, has "RAMP OPEN" and "RAMP CLOSE" positions, with spring return to center.
3. Transfer switches for each valve are located at the Auxiliary Control Panel (ACP). Transferring to the ACP has the same effect on the controller as an accident signal, because the controller will switch from manual to automatic level control.
4. Level indicating controllers (LIC-2, -4, -6, and -8) are provided for each valve set at a local control panel, located just outside the TDP room. It is by means of these controllers that the automatic level control setpoint is established.

3.1.10.3 Indication/Alarms

1. Valve position indicating lights at MCB
2. Valve controller MANUAL or AUTO indicating lights at MCB
3. Pipe break detection indication at MCB
4. Loop level indication at MCB
5. High and low SG level alarms at MCB
6. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
7. Input to Status Monitoring System to indicate that solenoids are deenergized, allowing valves to modulate

3.1.11 Level Control Valve Check Valves: C-12, -13, -14, -15, -16, -17, -18, and -19

3.1.11.1 Component Function and Design Features

The level control valve check valves (LCVCVs) are 4-in. swing check valves that open to allow pump discharge flow to reach the SGs. The LCVCVs , along with pump DCVs, prevent flow reversal from another pump if a pump fails to start. The LCVCVs also prevent, along with the level control valves and the pump DCVs, backleakage from hot, pressurized main feedwater during normal operation. The LCVCVs form a pipe class boundary consistent with the latter function; piping downstream of the LCVCVs has design pressure and temperature ratings of 1085 psig and 600°F, whereas piping upstream of the LCVCVs is rated at 1650 psig and 120°F.

Under design basis flow (220 gal/min) conditions, the average velocity in the 4-in. piping at the LCVCV is ~6 ft/s. At the "batching" flow rate used in support of shutdown/startup evolutions of 75 gal/min, the velocity is ~2 ft/s.

The TDP LCVCVs are located in a run of piping and valves that would greatly contribute to flow turbulence in the vicinity. A simplified schematic of the layout (not to scale) is shown in Fig. 3.6. As shown, the LCVCV is located immediately downstream of the LCV, and 90° elbows are in close proximity to isolation valves located just upstream and downstream.

The MDP LCVCVs are not symmetric in arrangement. The "A" and "B" MDP LCVCVs are arranged as indicated in Fig. 3.7. As shown in the figure, the "A" pump LCVCVs would be subject to more turbulence because of the elbow located just upstream (~1 ft).

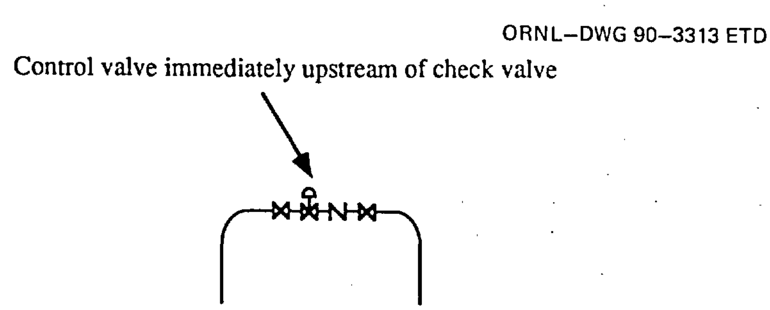

Fig. 3.6. Turbine-driven pump level control valve check valve configuration.

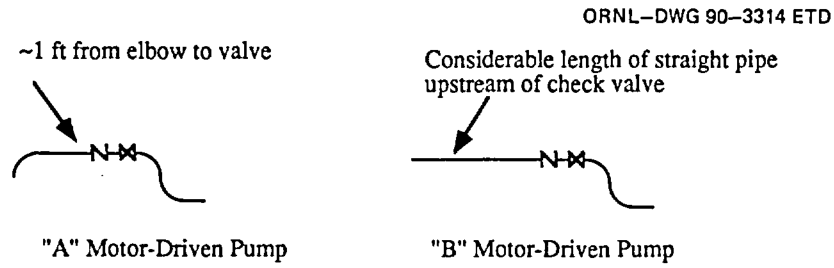

Fig. 3.7. Motor-driven pump level control valve check valve configurations.

3.1.12 SG B and C AFW to Main Feed Check Valves: C-21, -22, -24, and -25

3.1.12.1 Component Function and Design Features

The main feed check valves (MFCVs) open to allow pump discharge flow to reach the SGs. The MFCVs (along with the level control valves, level control valve check valves, and the pump discharge check valves) prevent backleakage from hot, pressurized main feedwater during normal operation. The MFCVs are located inside containment. No comparable valves are in the AFW to SG A and D main feed lines (the AFW to main feed connection for these SGs is outside of containment).

The MFCVs are 4-in. swing check valves. Under design basis flow (220 gal/min) conditions, the average velocity in the 4-in. piping at the MFCVs is ~6 ft/s. At the "batching" flow rate used in support of shutdown/startup evolutions of 75 gal/min per SG, the velocity is ~2 ft/s. The piping arrangement for the MFCVs is depicted in Fig. 3.8. The upstream MFCV is located immediately downstream of an elbow, and the second MFCV is located ~4 in. downstream.

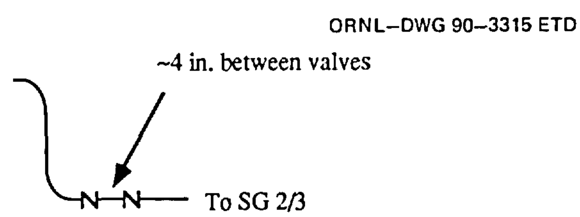

Fig. 3.8. AFW to main feedwater check valve configuration.

3.1.13. Main Feedwater Check Valves: C-20, -23, -26, and -27

3.1.13.1. Component Function and Design Features

The main feedwater check valves (FWCVs) must close in the event of loss of main feedwater flow to ensure that adequate AFW flow is delivered to the SGs.

The FWCVs are 16-in. swing check valves. The normal, full-power flow condition for each FWCV is ~9000 gal/min, with an average velocity of ~18 ft/s. This velocity should be sufficient to both maintain the FWCVs in the fully open position and avoid fluttering, as long as the plant is operated at full-power conditions.

3.1.14 Feedwater Isolation Valves: FWIV-1, -2, -3, and -4

3.1.14.1. Component Function and Design Features

The FWIVs, which are normally open to allow passage of feedwater to the SGs, close automatically in response to the following signals:

1. any SI signal,
2. hi-hi level (on 2/3 channels) in the serviced SG, and
3. reactor trip and low T_{avg} (2/4 channels).

From the standpoint of the AFW system, the principal purpose of the FWIVs is, along with check valves located downstream of the FWIVs, to provide an isolation between the AFW connections to the main feed lines and the nonsafety portion of the main feedwater system, thereby assuring that auxiliary feedwater is delivered to the SGs.

The FWIVs are 16-in. gate valves with 480-V ac motor operators (LIMITORQUE SB-4). The thermal overload heaters for the FWIVs have been replaced with jumpers. Motor deenergization during a close stroke, whether initiated manually or automatically, occurs when the "ac" limit switch opens. Motor deenergization during the open stroke (note that all open strokes are manually initiated) occurs when the "bo" limit switch opens. No torque switches are incorporated into the FWIV control circuits. Also, no thermal overload protection is provided for the FWIVs, because the thermal overload heaters have been removed and replaced with jumpers.

Note that the FWIVs do not close automatically for all AFW automatic start signals (e.g., low-low SG level or blackout). In fact, the automatic closure signals are oriented toward avoiding excessive cooldown rates or overfilling of the SGs rather than to support the AFW system functions.

3.1.14.2 Controls

1. The MCB switches for the FWIVs have "OPEN," "CLOSE," and "AUTO" positions. Both the "OPEN" and "CLOSE" positions are spring return to "AUTO."
2. Transfer and OPEN/CLOSE control switches are also provided at the MCCs.

3.1.14.3 Indication/Alarms

1. Valve position indicating lights at MCB and MCCs
2. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
3. Status monitoring system inputs: valve closed; no power to valve operator

3.1.15 SG Blowdown Isolation Valves (BDIVs): BDV-1, -2, -3, and -4

3.1.15.1 Component Function and Design Features

One BDIV is located in each SG blowdown line, outside of containment. The BDIVs must close in response to start of any AFW pump to ensure that the AFW flow delivered to the SGs can be converted to steam and released through the main steam safeties or PORVs (instead of being drained off as liquid through the blowdown lines), thereby accomplishing the intended heat-removal function.

The BDIVs are 2-in. air-operated angle valves that fail closed on loss of air or solenoid power and close automatically in response to the start of AFW pumps. The BDIVs are train oriented. The BDIVs from SGs A and C close on the start of the B MDP or the TDP, and the BDIVs from SGs B and D close on the start of an MDP or the TDP.

The pump-start indications used by the control circuitry for the BDIVs are

1. MDPs: 52S/b pump breaker auxiliary contacts, and
2. TDP: T&T valve stem actuated limit switch (bc position).

The BDIVs also receive a close signal on a Containment Phase A Isolation (the only automatic Phase A Isolation comes from an SI signal). Note that each BDIV is in series with another (e.g., BDV-1A is in series with BDV-1, with BDV-1A located inside of containment and BDV-1 outside). The inside containment blowdown isolation valves receive an automatic closure signal on Phase A Isolation, but not on AFW pump start. To provide for a single-failure proof design, from the containment isolation standpoint, the inside and outside valves receive their closure signals and solenoid power from different trains; for example, BDV-1 receives its Phase A Isolation signal from the B train of the Solid State Protection System, whereas BDV-1A receives its signal from train A.

A couple of noteworthy design features are associated with the BDIVs. As noted previously, the BDIVs from SGs A and C close on the start of the B MDP (or the TDP). However, the B MDP feeds SGs C and D. Similarly, the BDIVs from SGs B and D close on start of the MDP that feeds SGs A and B. A second notable feature is that although from a containment Phase A Isolation standpoint valve redundancy is provided in the SG blowdown isolation system, there is no *valve* redundancy from the standpoint of closure on AFW starting. There is redundancy, from a closure signal standpoint because each BDIV receives a closure signal from both the start of an MDP as well as the TDP (which, in turn, receives start signals from both trains).

3.1.15.2 Controls

The control switches for the BDIVs are ganged switches, with a single handswitch controlling both BDV-1 and -1A. Individual transfer switches are provided for each valve (including separate switches for the inside containment valves) in the auxiliary control room. Repositioning the transfer switches from "NOR" (MCB Control) to "AUX" results in deenergization of the valve solenoid, thereby closing the valve. The BDIVs have no other control switch.

The BDIVs can be reopened from the MCB by the operator following closure in response to an AFW pump start (even if the AFW pump is still running) by taking the handswitch to the open position (and holding it in the open position until fully open).

3.1.15.3 Indication/Alarms

1. Valve position indicating lights at MCB
2. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator

3.1.16 AFW Turbine Steam Supply Valves: MOV-11 and -12

3.1.16.1 Component Function and Design Features

The AFW turbine is supplied with a normal steam supply source, SG A, via normally open MOV-11. If SG A is unavailable to supply steam to the turbine (e.g., in the event of a feedline break to SG A), an alternate steam supply is automatically provided from SG D via normally closed MOV-12.

The steam supply valves (SSVs) are 4-in. gate valves. They are equipped with 480-V ac motor operators (LIMITORQUE SMB-00) that are powered by two separate safety-related busses.

If the TDP discharge pressure has not reached 100 psia within 60 s after the T&T valve has begun to open, the control circuit for the SSVs is designed to transfer steam supply sources for the turbine automatically (See Fig. 3.9). Three permissives are necessary for the transfer to initiate:

1. the T&T valve has started to open (note that a seal-in of this portion of the permissive exists until either the required pump discharge pressure is reached or until MOV-12 is fully open),
2. MOV-12 is not fully open ("bo" contacts are closed), and
3. the TDP discharge pressure, as sensed by PS-10, has not reached 100 psia.

If these permissives are met for 60 s, a relay energizes that causes the T&T valve to reclose and MOV-11 to close. Once MOV-11 is closed, MOV-12 will start to open. The T&T valve will start to reopen as soon as it has closed. If MOV-12 reaches full open before the T&T valve, both valves will stay open. However, if the T&T valve reaches full open before MOV-12, it will cycle closed and open again (and will continue to cycle closed/open until MOV-12 is fully open).

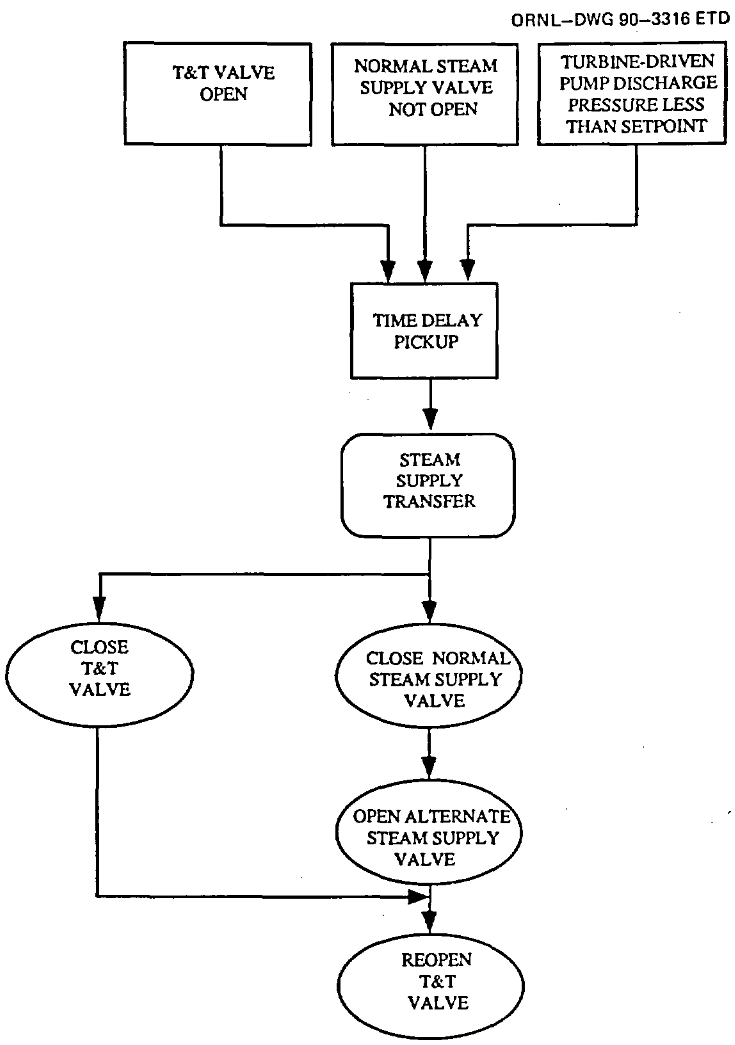

Fig. 3.9. Turbine steam supply transfer sequence.

MOV-11 motor operator rotor-actuated limit switches are used for the following purposes in MOV-12:

1. "bc" contacts provide the permissive to allow the MOV-12 open coil to energize in conjunction with the automatic steam supply transfer, and
2. "ac" contacts cause MOV-12 to close if it is opened with MOV-11 not closed.

Both valves have seal-in circuits for their open and close coils.

The SSVs include thermal overload contacts, which are not bypassed, in both the open- and close-coil circuits. The open coil for each valve motor is deenergized by a limit switch (no torque switches are provided in the open-coil circuits). The close-coil circuit includes a torque switch that is bypassed by a limit switch, except for the final 2 to 3% of stroke.

3.1.16.2 Controls

1. MCB valve handswitches (HS-11A and HS-12A) with "CLOSE," "OPEN," and "AUTO." Both "CLOSE" and "OPEN" are spring return to "AUTO."
2. MCC open/close switches (HS-11C and HS-12C).
3. Transfer switches located at the MCCs, with "NOR" and "AUX" positions (XS-11 and XS-12). In "NOR," the MCB controls are enabled, and in "AUX," the MCC switches are enabled. The automatic functions of the valves are enabled with the transfer switches in either position.

3.1.16.3 Indication/Alarms

1. Valve position indicating lights at MCB and MCC provide input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
2. Status monitoring system inputs: valve closed; no power to valve operator

3.1.17 AFW Turbine Steam Supply Isolation Valves: MOV-9 and -10

3.1.17.1 Component Function and Design Features

The steam supply isolation valves (SSIVs) provide automatic isolation of the common steam supply header from the AFW turbine if a high-temperature condition (148°F) is detected in the TDP room.

The SSIVs are 4-in. gate valves. They are equipped with 480-V ac motor operators (LIMITORQUE SMB-00) that are powered by two separate safety-related busses.

When a high-temperature condition is sensed , the close coil is energized to drive the valve shut. Two temperature switches that are wired in series must sense a high-temperature condition for a valve to close (two temperature switches are dedicated to each valve).

The SSIVs include thermal overload contacts, which are not bypassed, in both the open- and close-coil circuits. The open coil for each valve motor is deenergized by a limit switch (no torque switches are provided in the open coil circuits). The close-coil circuit includes a torque switch that is bypassed by a limit switch, except for the final 2 to 3% of stroke.

3.1.17.2 Controls

1. MCB and MCC valve handswitches (HS-9 and -10), with "PULL AUTO," "IN-MAN," "CLOSE," and "OPEN" positions (the CLOSE and OPEN positions are used

with the handswitch pushed in for manual valve operation). The handswitches are spring return to Auto.
2. Transfer switches located at the MCCs, with "NOR" and "AUX" positions (XS-9 and -10). In "NOR," the MCB controls are enabled, and in "AUX," the MCC switches are enabled. The automatic functions of the valves are enabled with the transfer switches in either position.

3.1.17.3 Indication/Alarms

1. Valve position indicating lights at MCB and MCC
2. Input to the "TRANSFER SWITCH IN AUX MODE" common annunciator
3. Status monitoring system inputs: valve closed; no power to valve operator; MCB valve handswitch not in auto

3.2 REVIEW OF PROCEDURES RELATING TO AFW COMPONENTS

When plants are originally designed, analyses are performed to verify that safety-related systems, such as the AFW system, will be able to function to mitigate effectively the consequences of design basis accidents and transients. These analyses are documented in the FSAR (typically Chap. 15). Inherent in these safety analyses are assumptions relative to normal alignments, equipment availability and capability, automatic actions, and other characteristics. Although changes to the plant design and procedures that control plant and system operation may be made (as long as the constraints dictated in 10 CFR 50.59 are satisfied), it is critical that the plant be maintained within the envelope of assumptions made in the safety analyses.

As a part of the plant operating license, plants are issued a set of Technical Specifications that must be met. Tech Specs specify minimum operating condition requirements for systems and components, referred to as Limiting Conditions for Operation (LCO). The Tech Specs also specify surveillance requirements that designate, in general terms, the scope and frequency of, as well as acceptance criteria for, testing that must be performed to verify satisfaction of the LCO. The primary intent of the Tech Specs is to ensure regularly the continuing validity of assumptions made in conjunction with safety analyses.

Whereas Tech Specs provide the general skeleton or framework for this continuing validation of safety analysis assumptions, the individual plant surveillance procedures, developed specifically to meet the Tech Spec requirements, are actually used to perform the validation.

Several Tech Specs for the Plant A address aspects of the AFW system. The Tech Specs that are listed in Appendix A, while plant-specific, are fairly representative of those for most operating plants.

A review of procedures related to the monitoring and operation of the AFW system at Plant A was conducted to

1. determine the extent to which the various types of failures could be detected by programmatic monitoring or routine operating practices, and
2. estimate the amount of service associated with testing of the components.

Although relevant operating and maintenance procedures were also reviewed, the principal focus of this review was the set of procedures that are used to satisfy AFW-related surveillance requirements.

Monitoring practices and operating guidelines relative to each of the component types discussed in Sect. 3.1 follow. The general purpose of each procedure as it relates to the subject component, estimates of the service associated with testing, and pertinent comments are provided. Note that the frequency of testing-related operation tables that are provided for each component may include procedures not discussed for that component because the component may be actuated by a test that is not used to demonstrate operability of the component but that does cause its operation. An example of this would be where an SI signal is simulated to verify that an MDP starts in response to the SI signal. The TDP would also start (or at least the T&T valve would open) in response to this signal, but the test may not be used to demonstrate operability of the TDP.

Based on the review of the surveillance, operating, and maintenance procedures, a compilation of failure sources that would not be detectable by the current monitoring practices was developed. A summary of this compilation is provided in Sect. 3.3.

Note that at the time that the review of the surveillance, maintenance, and operating practices was being conducted, several fairly significant procedural revisions, as well as complete rewrites, were in process. In fact, some previously nondetectable failure sources were made detectable as a result of changes. Because this process was ongoing, some of the observations made relative to failure nondetectability will probably be invalid when this report is issued. The observations should be recognized for what they are – a picture of the monitoring/operational practices in place for a specific plant at a particular time. It is believed, however, that these observations are reasonable indicators of AFW system monitoring practices as a whole.

3.2.1 Pump Suction Check Valves: C-3, -4, and -5

3.2.1.1 Surveillance and maintenance tests/inspections

ST-8 and -9 are quarterly tests in which the AFW pumps are run in their recirculation flow path. These tests are performed to meet ASME Section XI testing requirements for the pumps and are also used to demonstrate partial stroking of the SCVs. The flow rates through the valves during this testing is ~1/10 of the required design flow.

ST-14 is performed quarterly to verify that the SCVs close under reverse pressure/flow conditions. The test is performed by pressurizing the piping downstream of the SCV with demineralized water (using a vent connection on the pump casing) and observing that a reverse pressure differential of $\geq$3 psid exists across the SCV.

ST-15, which is performed during each entry into hot standby conditions, demonstrates that the pumps can deliver design basis flow to the SGs. The test thereby demonstrates that the SCVs stroke open sufficiently to allow the required flow to pass through them. The total of flow rates to the SGs must be $\geq$440 gal/min for the MDPs and $\geq$880 gal/min for the TDP. Note that flow through the check valves would exceed flow delivered to the SGs by the amount of flow delivered through the recirculation flow path.

ST-28, which is performed on a refueling frequency, calls for the disassembly and inspection of several check valves. Note that this ST is not performed to meet a specific Tech Spec surveillance requirement, and is not required by the ASME Section XI program, but is performed as a consequence of the San Onofre water hammer event (see NUREG-1190[1] and IE Notice 86-09[2]). The valves are organized in groups of four. One valve out of each group is disassembled and inspected each refueling outage; so each valve will be inspected about every 6 years. If a valve fails to meet the acceptance criteria (see below), all other valves in the group are to be inspected during the same outage. The TDP SCV, along with the DCVs, make up one group of valves to be disassembled and inspected in ST-28.

Acceptance criteria are

1. all internal parts in place and showing no signs of abnormal wear;
2. all internal locking devices, including tack welds, in place and in good condition; and
3. all internal surfaces in good condition and showing no signs of abnormal wear.

3.2.1.2 Frequency of test operation

The MDP SCVs are stroked according to the following procedures:

Procedure	Number of full(F)/partial(P) strokes	Frequency
ST-3A	5P	Refueling
ST-6	5P	Refueling
ST-9	1P	Quarterly
ST-15	1F	Hot standby (≤quarterly)[a]
ST-16	1P	Refueling
MI-2A and -2B	1P	Refueling[b]
MI-3A and -3B	1P	Refueling[b]

[a] It is assumed that this test is performed twice per year.

[b] The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related partial strokes per year: The test frequency information given above would yield ~13 partial strokes per year; however, the MDPs are used for protracted periods during startups and shutdowns and with varying flow rates, with the dominant amount of time spent at relatively low flow rates or in recirculation flow only. Thus, the valves are partial stroked much more frequently than indicated by testing.

Total estimated test-related full strokes per year: 2. (The only time the valves would be likely to experience full stroking would be during testing, although some infrequent operational demands could result in substantial, if not design basis, flow rates through the valves.)

The TDP SCV is stroked per the following procedures:

Procedure	Number of full(F)/partial(P) strokes	Frequency
ST-7	3P	Refueling
ST-8	2P	Quarterly
ST-15	2F	Hot standby (≤quarterly)[a]
ST-27	2P	Refueling

[a] It is assumed that this test is performed twice per year.

Total estimated test-related partial strokes per year: 11. Note that the TDP normally would not be used to support startups or shutdowns.

Total estimated test-related full strokes per year: 4. The only time the valves would be likely to experience full stroking would be during testing although some infrequent operational demands could result in substantial, if not design basis, flow rates through the valves. Note that the phrase "full strokes" refers to conditions under which the flow rate through the valve is at or near the maximum that occurs, not necessarily a condition under which the check valve is fully open.

3.2.1.3. Relevant operating instructions

Because the TDP would be seldom used to support startup/shutdown evolutions, the normal operating procedures primarily affect the MDP SCVs.

OP-1 includes precautions that state:

> AFW Pumps should continue to run on recirculation to avoid hanger damage and extend motor life. AFW LCV's should be maintained in manual to avoid steady-state low flow conditions that could result in damage to hangers in the Turbine Building, Condensate Transfer Pump damage, and/or intermittent actuation of AFW pump suction pressure switches. Just prior to criticality LCV Controller will be placed in AUTO positions.
>
> While in a low flow condition or Mode 3, AFW should be "batched" or "slugged" at $\simeq$75 gal/min to each steam generator to prevent vibration damage and inadvertent ESW swapover. This flowrate will also ensure that S/G nozzle cracking does not occur.

GOP-1 (Unit Heatup from Cold Shutdown to Hot Standby) and GOP-2 (Plant Startup from Hot Standby to Minimum Load) include similar precautionary statements.

3.2.1.4 Comments

A noteworthy feature of the testing program for the SCVs is the fact that the TDP SCV is included in the periodic disassembly and inspection procedure (ST-28), whereas the MDP SCVs are not. This is difficult to understand in that the MDP SCVs see considerably more service because the MDPs are used to support plant startup and shutdown. Also note that the low suction pressure switches for the MDPs are located upstream of the SCV's; thus, failure of an SCV to open fully, thereby creating low suction pressure conditions at the pump suction (but not upstream of the check valves) could occur and not be detected by the suction pressure switches.

The extremely low velocities that the MDP SCVs would experience, in conjunction with the fact that the layout geometry is not particularly beneficial for flow stability (because of the proximity of the upstream elbow), indicate that the probability of disk oscillation related wear would be relatively high (in comparison with that experienced by the average check valve in a standby system). Although the wear rate as a function of hours of service would be expected to be relatively high, the wear rate as a function of plant life should be relatively low (because the system is not in service the vast majority of the time).

3.2.2 Emergency Service Water to Motor-Driven Pump Suction Isolation Valves: MOV-1, -2, -3, and -4

3.2.2.1 Surveillance and maintenance tests/inspections

ST-6, which is performed every 18 months, is used to satisfy Tech Spec Surveillance Requirement 4.7.1.2.b for the MDP ESW valves. The testing is performed on only one of the two in-series valves at a time to avoid intrusion of ESW water (lake water) into the AFW system; therefore, the valves are stroked under low- or no-flow conditions (some minor flow does occur during the MOV-2 and -4 valve tests because the tell-tale drain valves between the two isolation valves are open). The automatic stroking is initiated by manually closing the associated pump breaker auxiliary contacts to simulate a pump running condition and by depressurizing *all three* suction pressure switches. The testing sequence for each pump's valve set is to test each upstream valve (MOV-1 or -3) first and then test the downstream valve (MOV-2 or -4). The upstream valve (MOV-1 or -3) is stroked after the breaker for the downstream valve's motor operator is opened. To accomplish the testing of the downstream valves (MOV-2 or -4), the procedure calls for the "thermal overloads" ("thermal overloads" is procedure terminology – note that the thermal overloads for these valves have been removed and replaced by jumpers) to be removed from MOV-1 or -3 after completing the MOV-1 or -3 portion of the test. This requirement allows the suction pressure switches to energize the relays that automatically open MOV-2 or -4 without causing MOV-1 or -3 to open (the low suction pressure relays are located in the MCCs for MOV-1 and -3). MOV-1 and -3 are not restroked after testing MOV-2 and -4.

ST-10, -11, and -13 are used to implement the ASME Section XI valve in-service testing requirements. The testing sequence called for is to first test the downstream valve and then test the upstream valve to avoid intrusion of lake water into the AFW system. The tell-tale drain is closed during the valve stroking and reopened following completion of the test. Stroking is performed by use of the MCB switch. The maximum allowable stroke time for each of the four valves is 42 s.

ST-25 is a calibration and functional test procedure that satisfies Tech Spec Surveillance Requirements 4.3.2.1.1.B.6.g (calibration) and 4.3.2.1.1.C.6.g (functional test). The functional test is required every 31 days, and the calibration is required every 18 months.

The general testing sequence is as follows:

1. The associated MDP control switch is placed in PULL TO LOCK to prevent inadvertent stroking of either valve (because the pump must be running to complete the open permissive).
2. The downstream valve breaker is opened to prevent the valve from inadvertently opening.
3. The "A" pressure switch is isolated and depressurized, and the associated MCB alarm is verified.
4. Using a test rig, the pressure at the switch is varied, and the switch setpoint is checked (and adjusted, if necessary). The test rig is then disconnected, the pressure switch is unisolated, and the alarm is verified to have cleared.
5. Similar checks are performed on the "B" and "D" switches, except that following the check on the "D" switch, the "D" switch is left isolated and depressurized. The "B" switch is then isolated and depressurized, and the contacts that must close to cause the "A" and "B" valves to open are verified to be closed.
6. The switches are then restored to normal configuration and their sensing lines refilled.

Note that only the B + D pressure switch coincidence is checked. Also note that no distinction is made in the procedure between the channel functional test and the channel calibration.

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators that is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting the limit switch positions according to MI-6A; measuring resistance from each phase to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6A is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, based either on valve travel measurement or the number of handwheel turns, are set as follows: (1) open limit switch set to open at 95 to 98% of valve travel, and (2) close limit switch set to open at 97 to 98% of valve travel.

MI-7 is used to verify the time delay relays associated with the automatic transfer from the CST to ESW time out at 4 s. The procedure does not actuate any equipment – it only verifies timing. There is no designated frequency of testing. A commitment to periodically calibrate the timers was made in a licensee event report (LER) filed by Plant A.

3.2.2.2 Frequency of test operation

The ESW isolation valves are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-6	1	Refueling
ST-10 and -13	1	Quarterly

Total estimated test-related full strokes per year: 5. All strokes are performed under no-flow conditions.

3.2.2.3 Relevant operating instructions

OP-1, which is the AFW system operating procedure, specifies that the ESW isolation valves are to be "Operable-Closed" and the telltale drain valves "Open." The Precautions section states that "If the suction pressure of the motor-driven AFW pumps fall below 2 psig for 4 s, the suction will shift from CST to ESW. If suction swaps over, Assistant Unit Operator (AUO) should close telltale valves on all AFW Pumps." The procedure also includes instructions on switching the suction source from CST to ESW if "pump suction drops to 2 psig and auto swap over does not occur." Manually switching to ESW requires shift supervisor approval and is accomplished in the following sequence:

1. close telltale drain valve,
2. open the outboard valve (e.g., MOV-1), and
3. open the inboard valve (e.g., MOV-2).

Note that the operator does not have remote indication of suction pressure, but there is a local suction pressure gage for each pump.

A single low suction pressure alarm annunciates when any one of the pressure switches for either of the MDPs or the TDP closes (total of nine pressure switches).

OP-3 is the annunciator response procedure for AFW-related alarms. The annunciator procedure states that the origin of the annunciator is from PS-1A, -2A, or -3A. (In reality, the B or D switches for each of the sets will also cause annunciation.) It also states that if 2/3 pressure switches for a given pump reach their setpoint, the pump will automatically switch over to ESW as the suction source. The "Immediate Action" section of OP-3 has the operator "verify opening of appropriate ESW suction supply valves."

3.2.2.4 Comments

Several comments are relative to the testing of these valves:

1. Because there is no indication of suction pressure in the main control room, when a low suction pressure alarm is received, the operator cannot know whether multiple switches

on multiple pumps have "made" because of an actual low suction pressure condition or whether only a single switch has closed spuriously. Therefore, the operator cannot know which are the "appropriate" valves (as designated in OP-3). (It has been observed at another plant that when the motor-driven AFW pumps are started up with their discharge valves to the SGs open, a low-suction pressure alarm annunciates routinely because of transient pressure conditions. However, when started up on recirculation flow only, the alarm is not received. Note that this plant has suction pressure indication in the main control room for all AFW pumps, as opposed to Plant A, which has no indication.)

Given the natural reluctance of an operator to switch over to ESW and the availability of only a single annunciator operated from multiple switches, along with the operating procedure requirement to secure shift supervisor permission before switching to ESW in the operating procedure (OP-1), considerable question exists concerning how the operator would respond to an alarm. Note that no time delay is associated with the suction pressure *alarm* (instead, the delay is built into the automatic valve opening circuit).

2. No testing currently conducted can verify that these valves will open in conjunction with an actual low suction pressure condition and that the pumps running will achieve satisfactory results ("satisfactory results" include the requirements that (1) the pump suction switchover takes place quickly enough to prevent loss of required NPSH for the pumps and (2) adequate steady state flow is provided to the pumps to allow the AFW design-flow requirements to be met). Because of the water chemistry problems associated with the switchover, there is an understandable desire not to test this feature. However, because ESW is the only safety-grade source of water for the pumps, the ability for the transfer to occur satisfactorily is critical.
3. Manual isolation valves and check valves are between the pressure switches and the MDPs. Thus, the pressure switches would not detect and correct for a stuck closed check valve or an improperly positioned manual isolation valve.
4. Because no flow is delivered through the valves, the capability of the suction flow paths to support required AFW flow is not demonstrated.
5. The A + B and A + D pressure switch logic is not verified to result in valve opening.
6. ST-6 does not verify restoration of operability for MOV-1 and -3 following replacement of the "thermal overloads" (jumpers) after testing MOV-2 and -4. Inasmuch as the part of the control circuit that is needed for valve operation is interrupted for the test, but the valve position indicator lights portion of the control circuit remains intact, continuity in the valve operation portion of the circuit is not verified to have been reestablished.
7. The pipe configuration associated with the ESW suction valves is such that a small amount of lake water will intrude into the AFW system each time the inboard valve is stroked because the ESW valves are located in a vertical section of pipe. Because this section of piping is normally relatively stagnant, the potential for Asiatic Clam buildup and/or microbiologically induced corrosion exists. However, the procedure that is implemented to deal with Asiatic Clams (ST-30) opens up bypass treatment lines in the ESW to AFW pump suction piping to ensure that the lines are treated when environmental (temperature) conditions warrant action to minimize Asiatic Clam buildup. Note that ST-6, which is performed every 18 months, provides for flushing out any ESW water left after the upstream valves are stroked by leaving the drain valves open during the downstream valve stroking. However, this good practice is not adopted in ST-10, which is performed quarterly.
8. The section of piping downstream of each MDP's check valve in the normal suction path from the CST is safety-grade, seismically qualified piping, whereas the piping upstream of the check valve is not. The length of piping downstream of the check valve to the MDP contains only enough water for a couple of seconds of pump operation before air would be drawn into the pump casing should the piping upstream of the check valve fail. It appears that the time delay before automatic valve opening

was initiated, as well as the fact that the valves are fairly slow stroking valves, might create conditions under which the MDPs became at least partially air-filled before the transfer was completed. Note that this concern is common with the TDP.

3.2.3 Emergency Service Water to Turbine-Driven Pump Suction Isolation Valves: MOV-5, -6, -7, and -8

3.2.3.1 Surveillance and maintenance tests/inspections

ST-7, which is performed every 18 months, is used to satisfy Tech Spec Surveillance Requirement 4.7.1.2.b for the TDP ESW valves. The testing is performed on only one of the two in-series valves at a time to avoid intrusion of ESW water (lake water) into the AFW system; therefore, the valves are stroked under no-flow conditions. The automatic stroking is initiated by manually opening the T&T valve (with an upstream steam supply valve closed to prevent a pump start) and by depressurizing *all three* suction pressure switches. The testing sequence for each pump is to first test the upstream valve and then test the downstream valve to avoid intrusion of lake water into the AFW system. The test provides evidence that the valve sequencing (MOV-7 or -8 valve begins to open, then MOV-5 or -6 valve begins to open, and then MOV-7 or -8 valve closes) takes place, although the sequence is not timed. Note that the test, as written, will actually cause the MOV-7 or -8 valve to stroke open, then shut, and repeat the cycle until either the T&T valve is opened or two of the three suction pressure switches are repressurized.

ST-10, -11, and -13 are used to implement the ASME Section XI valve in-service testing requirements. Stroking is performed by using the MCB switch. The maximum allowable stroke time for each of the four valves is 55 s. The tell-tale drain valve is closed during testing and reopened after testing.

ST-25 is a calibration and functional test procedure that satisfies Tech Spec Surveillance Requirements 4.3.2.1.1.B.6.g (calibration) and 4.3.2.1.1.C.6.g (functional test). The functional test is required every 31 days, and the calibration is required every 18 months.

With the breakers for MOV-7 and -8 and MOV-5 and -6 open (to prevent valve stroking), the pressure switches (PS-3A, B, and C) are checked, one at a time, to verify that the switch closes at the proper suction pressure (using a pressure source, with the pressure switch isolated from the suction header). The low suction pressure alarm at the MCB is verified to come in and then to clear for each switch.

After the pressure switches are checked/calibrated, a portion of the automatic switchover circuitry is verified as follows:

1. the steam supply to turbine is isolated by closing MOV-9 and -10,
2. the T&T valve is opened (needed to provide permissive), and
3. each of the 2/3 pressure switch coincidence logic combinations is checked to verify that relays BBA, BBB, and CCC energize.

No distinction is made in the procedure between the channel functional test and the channel calibration.

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators that is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting of the limit switch positions according to MI-6A; measuring resistance from each phase to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6A is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, which can be set based either on valve travel measurement or the number of handwheel turns, are set as follows: (1) open limit switch set to open at 95 to 98% of valve travel, and (2) close limit switch set to open at 97 to 98% of valve travel.

MI-7 is used to verify the time delay relays associated with the automatic transfer from the CST to ESW times out at 5.5 s. The procedure does not actuate any equipment – it only verifies timing. There is no designated frequency of testing. A commitment to periodically calibrate the timers was made in an LER filed by Plant A.

3.2.3.2 Frequency of test operation

The ESW isolation valves are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-7	1[a]	Refueling
ST-10 and -13	1	Quarterly

[a] MOV-7 and -8 will be stroked open and closed continuously in ST-7 until the T&T valve is closed; however, only one stroke is assumed here.

Total estimated test-related full strokes per year: 5. All strokes performed under no-flow conditions.

3.2.3.3 Relevant operating instructions

See the discussion under Sect. 3.2.2.3 for ESW supply valves MOV-1, -2, -3, and -4.

3.2.3.4 Comments

No testing is conducted to verify that these valves will open in conjunction with an actual low-suction pressure condition and the pump running will achieve satisfactory results ("satisfactory results" include the requirements that (1) the pump suction switchover takes place quickly enough to prevent loss of required NPSH for the pump and (2) adequate flow is provided to the pump to allow the AFW design-flow requirements to be met). Because of the water chemistry problems associated with the switchover, there is an understandable desire not to test this feature. However, because ESW is the only safety-grade source of water for the pumps, the ability for the transfer to occur satisfactorily is critical. Because no flow is delivered through the valves, the capability of the alternate suction flow paths to support required AFW flow is not demonstrated.

The piping section between the valves (e.g., between MOV-7 and -8) is horizontal with a normally open telltale drain valve. This section of piping is thus normally air-filled. This should minimize the potential for Asiatic Clam and/or microbiologically induced corrosion in the piping between the valves but does cause some concern relative to the introduction of air into the pump in the event of automatic swapover. Water in the piping sections upstream of MOV-5 and -7 is normally relatively stagnant, and therefore the potential for Asiatic Clam buildup and/or microbiologically induced corrosion exists. Some mitigation is provided, however, because the procedure that is implemented to deal with

Asiatic Clams (ST-30) opens up bypass treatment lines in the ESW to AFW pump suction piping to ensure that the lines are treated when environmental (temperature) conditions warrant action to minimize Asiatic Clam buildup.

The length of piping downstream of the check valve in the normal suction path from the CST is safety-grade, seismically qualified piping, whereas the piping upstream of the check valve is not. The length of piping downstream of the check valve only contains enough water for a few seconds of pump operation before air would be drawn into the pump casing should the piping upstream of the check valve fail. It appears that the time delay before automatic valve opening was initiated, as well as the fact that the valves are fairly slow stroking valves, might create conditions under which the TDP became at least partially air-filled before the transfer was completed.

3.2.4 Motor-Driven AFW Pumps

3.2.4.1 Surveillance and maintenance tests/inspections

ST-3A and -3B (3A is for "A" train, and 3B is for "B" train), which are performed on an 18-month frequency, are titled "Loss of Offsite Power with SI DG A/2B-B Containment Isolation Test." Note that both trains are tested every 18 months. The testing for a single train is discussed below.

Several AFW pump-related functions are checked in this test:

1. The MDP is verified to be stripped from its bus following deenergization of the bus (note that diesel-generator start due to bus undervoltage is inhibited during bus deenergization).
2. With the bus still deenergized, an SI signal is initiated. This causes the diesel to start and causes loads (including the associated AFW pump) to sequence on.
3. After resetting the SB and SI signals, restoring normal power to the bus, and securing the diesel, another SI signal is generated. Both MDPs are verified to start on the SI signal.
4. After resetting the SI signal and performing testing that is not directly related to AFW, the associated AFW pump bus is deenergized, and the automatic diesel-generator start associated with undervoltage is unblocked, allowing the diesel to start and reenergize the bus. The associated AFW pump is verified to start.

Note that (1) the testing sequence in items 1 and 2 results in AFW pump start from an SI signal with a preexisting SB signal, (2) the testing sequence in item 3 results in pump start from SI only, and (3) the item 4 sequence starts the pump from SB only. All starts of the pumps are performed with the system aligned for recirculation flow only.

ST-6, which is performed on an 18-month frequency, is titled "Motor-Driven Auxiliary Feedwater Pump and Valve Automatic Actuation." The following test sequences are included in ST-6:

1. An SI signal is simulated by manually pushing the SI slave relay, and the MDPs are verified to start.
2. A low-low SG level in one SG is simulated by tripping 2/3 level bistables for a single SG, and the MDPs are verified to start.
3. A trip of the "A" main feed pump in coincidence with simulated plant power at >80% is verified to start both MDPs.
4. A trip of the "B" main feed pump in coincidence with simulated plant power at >80% is verified to start both MDPs.
5. A trip of both main feed pumps is verified to start both MDPs.

The pumps are not verified to start on an SB signal, since the procedure takes credit for the SB starts in ST-3A and -3B. All ST-6 starts of the AFW pumps are performed with the system aligned for recirculation flow only.

ST-9, which is a quarterly test, is titled "Motor Driven Auxiliary Feedwater Pumps." Each pump is started and run with the system aligned for recirculation flow only. The conditions monitored are flow, suction and discharge pressure, and vibration, according to ASME Section XI (which is invoked by Tech Spec 4.0.5) requirements. Flow through the pump miniflow line is measured using temporary ultrasonic flowmeters. Pump suction and discharge pressure are also monitored using test pressure gages. Vertical and horizontal vibration of the pump inboard bearing is also monitored. Acceptance criteria are as follows:

Parameter	Acceptable	Alert	Required action
	MDP "A" in-service test ranges		
Suction pressure, psig	$\geq$11	NA	<11
Pump delta-P, psid	1524 to 1661.5	(No low range) 1661.5 to 1677.8	<1524 and >1677.8
Flow rate, gal/min	29.4 to 45.1	26.0 to 29.4 and 45.1 to 47.2	<26.0 and >47.2
Horizontal vibration, mils	0 to 1.0	1.0 to 1.5	>1.5
Vertical vibration, mils	0 to 1.0	1.0 to 1.5	>1.5
	MDP "B" in-service test ranges		
Suction pressure, psig	$\geq$11	NA	<11
Pump delta-P, psid	1464 to 1565.4	(No low range) 1565.4 to 1580.7	<1464 and >1580.7
Flow rate, gal/min	27.1 to 41.6	23.9 to 27.1 and 41.6 to 43.5	<23.9 and >43.5
Horizontal vibration, mils	0 to 1.0	1.0 to 1.5	>1.5
Vertical vibration, mils	0 to 1.0	1.0 to 1.5	>1.5

ST-15, which is performed for each entry into Mode 3 (but not to exceed quarterly), is titled "AFW Check Valve Opening Test During Hot Standby and Hot Shutdown." While the purpose of the test is to demonstrate stroking of check valves in the lines between the pump discharge and the SGs, it is also the only test that demonstrates anything other than recirculation flow from the pumps. The acceptance criteria for the test are that each pump is able to deliver $\geq$220 gal/min simultaneously to each of the SGs serviced by the pump. Other than specifying that the testing is to be conducted in Mode 3 or 4, there are no prerequisites relative to system conditions (such as SG pressure).

ST-19, which is performed on an 18-month frequency, is titled "Automatic Load Sequence Timer Functional Test." The test verifies that the MDP sequencing timer time delays are set at 20 s nominal (19 to 21 s is the acceptable range).

ST-20, which is performed on an 18-month frequency, is titled "Response Time Test of Auxiliary Feedwater System Auto-Start Relays." It is performed in conjunction with ST-6 and, in fact, only specifies response time test points to be monitored during the performance of ST-6. The only AFW pump-related response times measured are those associated with trip of the main feed pumps. The times measured are from trip of the main feed pumps until energization of the relays that cause the AFW pumps to start. The times are used in ST-22 to determine system response time.

ST-22, which is performed on an 18-month frequency, is titled "Engineered Safety Feature Response Time Verification." No equipment is actuated by the test; rather, the test compiles response time measurements from several other surveillance procedures, including ST-20 and -21, as well as from several response time tests for portions of channels performed in several MI tests.

For each of the automatic AFW actuation signals, total channel response time is calculated. Four response times are calculated for each start signal:

1. TDP response time,
2. TDP LCV response time,
3. MDP response time, and
4. MDP LCV response time.

The greatest time of these four is taken as the total actuation response time.

Each of the four response times is calculated by adding several components that together make up (or simulate) the time from process change until the actuated equipment has reached its safety function condition (pumps have developed the required discharge pressure or valves have reached the full-open position). The maximum allowable response time specified in the procedure is 59.1 s (1.5% less than the Tech Spec value of 60 s to provide for recorder chart speed accuracy).

Since the MDPs, under SB conditions, would not be sequentially loaded onto the diesel until about 30 s after an undervoltage condition occurred, the MDPs or the MDP LCV response times should be greater than the TDP and TDP LCV response times. Note that the TDP and the LCVs are not dependent upon diesel starting, since their power and control circuits are dependent upon 125-V dc and 120-V ac vital power.

The SB response time inputs to ST-22 from MI-3A and -B are based on a combined SI/SB signal, and the response times measured are from the diesel start signal (instead of the undervoltage condition, which must exist for 1.5 s before the diesel start signal is generated) until the MDPs have reached full discharge pressure. Note that fixed "Response Time Factors" are added to the time inputs from MI-3A and -B (as well as those from MI-2A and -B) to account for the difference in pressure development time for recirculation conditions, under which the test is conducted, and full-flow conditions. The response time factors are variable and range from 3.32 s ("A" pump factor in MI-2A) to 4.96 s ("B" pump factor in MI-3B).

Also note that the response times calculated for the MDPs do not include any time associated with the automatic realignment of pump suction from the nonsafety-related source (CST) to the safety-related ESW source. A low suction pressure condition must exist for 4 s after pump start to initiate the automatic suction source transfer. The motor-operated valves that open to provide the alternate suction source have maximum allowable stroke times of 42 s specified in the ST-10, -11, -12, and -13 series of tests.

While not part of a formal procedure (rather, based on an operations group instruction letter), auxiliary operators check the temperatures of the pump discharge lines once per shift for evidence of backleakage of main feedwater. This monitoring is performed in response to IE Bulletin 85-01[3] and Generic Letter 88-03.[4]

3.2.4.2 Frequency of test operation

The MDPs are operated according to the following test procedures:

Procedure	Number of pump starts[a]	Frequency
ST-3	5	Refueling
ST-6	5	Refueling
ST-9	1	Quarterly
ST-15	1	Hot standby (≤quarterly)[b]
ST-16	1	Refueling
MI-2A and -2B	1	Alternate refueling[c]
MI-3A and -3B	1	Alternate refueling[c]

[a] Note that all of these starts, with the exception of ST-15, are performed under recirculation flow only, and, even in ST-15, the flow rate to the SGs is manually changed from a relatively low flow to ≥220 gal/min per SG by manual control.

[b] It is assumed that this test is performed twice per year.

[c] The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related starts per year: The above test frequency information would yield about 14 pump starts per year for testing purposes. Most of the testing would involve a brief time (few minutes) of pump operation. If the average pump run duration per test were 15 min, the average annual run time would be ~3.5 h. However, the MDPs would be used for protracted periods during startups and shutdowns at varying flow rates, with the dominant amount of time spent at relatively low flow rates or in recirculation flow only. Occasional pump starts could be expected in conjunction with reactor trips or other unplanned events. Thus, while the number of test-related *starts* may exceed the number of unplanned and nontest starts, the amount of time spent running for test purposes is expected to be small, relative to the amount of run time in support of normal plant evolutions.

3.2.4.3. Relevant operating procedures

OP-1 is the AFW system operating procedure. Several procedural requirements affecting MDP operation are included in the OP:

1. A precaution states that the AFW pumps should be run on recirculation flow (as opposed to stopping and starting the pumps) during conditions when SG demand is low to avoid hanger damage and to extend motor life. Another precaution stipulates that AFW should be batched at ≃75 gal/min (under manual LCV control) to each SG to prevent vibration damage and inadvertent swapover from the CST to ESW suction as well as to prevent SG nozzle cracking.
2. If time permits, the LCVs are taken under manual control and closed before starting an MDP.
3. Following pump start, the pumps are inspected locally (no specific direction provided for the inspection).
4. For purposes of placing the AFW system in its standby condition, the MDP control switches are specified to be in AUTO.
5. Precautions are included that the "pump discharge lines should be ≤125°F (cool to touch)" to ensure against backleakage binding of the pumps. Note that Plant A is probably less susceptible to backleakage than many other plants since its LCVs are

normally closed (some plants have only check valves between the pumps and the SGs or main feed lines).

6. The procedure recommends that operation of the MDPs at flow rates in excess of 525 gal/min be avoided when the SG pressure is between 385 and ~865 psig. The stated purpose is to avoid high levels of vibration around the cavitating venturi when the flow rate is high enough to result in cavitation. (Below 385 psig, the bypass LCVs should provide sufficient backpressure to prevent cavitation.)

GOP-1 and -2 and GOP-3 (Plant Shutdown from Minimum Load to Cold Shutdown) include some of the same precautions relative to operation of the MDPs. GOP-2 specifies that the AFW pumps be used to maintain SG level until the main feed pumps are maintaining SG level and specifies that the main feed pumps should be started at ~1% reactor power.

3.2.4.4 Comments

The flow testing of the MDPs is performed under recirculation flow (roughly 25 gal/min) conditions. This testing is done to satisfy Tech Spec 4.7.1.2 as well as ASME Section XI testing requirements. While the testing satisfies regulatory requirements, it does little in the way of demonstrating pump capability. In fact, the best evidence of pump capability provided by any testing is from ST-15, which verifies that each MDP is capable of delivering at least 440 gal/min to the two SGs served, although pressure conditions are not specified.

The operating procedures include precautions to minimize adverse effects upon the pump motors, piping hangers, and other system equipment. However, the actions taken to accomplish those ends are deleterious to the pumps. The pumps, during startup and shutdown periods when relatively low flow rates are required, are run continuously in recirculation. As discussed in NUREG/CR-4597,[5] operating pumps for long periods of time at low-flow conditions can result in accelerated pump degradation. IE Bulletin 88-04[6] discussed this problem and required utility response. It does not appear, based on the operating guidance offered by Plant A procedures, that this issue has been thoroughly addressed.

All of the automatic start signals for the MDPs are adequately verified by testing to result in pump starting. The pumps are also verified to be stripped from their buses in the event that an undervoltage condition occurs with the pumps already running. All automatic start signal testing is done with the pumps aligned for recirculation flow only. One of the tests in which automatic loading is verified is ST-3A and -3B. This test is principally oriented toward demonstrating diesel operability, including verification that the automatically connected diesel loads do not exceed the diesel's 2000-h rating. Note that, as conducted, the test does not accurately simulate demand condition loads, since the AFW pumps (as well as other pumps) are operating under recirculation flow only, and since the power demanded under recirculation would be substantially less (roughly half) than that at full flow.

The ability for the pumps to successfully negotiate the transition from their normal source of water (CST) to their safety-related source (ESW) is not demonstrated. Actual delivery of lake water into the AFW system is clearly not desirable from a chemistry perspective. However, the time requirement for sensing a low-suction-pressure condition, timing out of the time delay relay, and opening of the ESW valves sufficiently to meet pump flow requirements appears to be marginal from the standpoint of ensuring that a pump would not become vapor bound.

The pump auxiliary contacts, which provide control signals to the LCVs, the alternate suction source valves, and SG blowdown valves, are not verified to function properly.

The response times measured for the MDPs include an allowance for the time required to reach the required flow rate (as an adder to the time required to reach steady-state pressure in the recirculation condition) but do not include an allowance for the time that would be required for the automatic transfer of the suction source from the CST to ESW. If the MDP response time were defined to include the maximum allowable stroke time for the alternate suction source valves, the pumps would not be able to satisfy the 60-s response time identified in Tech Specs. The 60 s is a somewhat arbitrary, generic Tech Spec time. Some accident/transient analyses do take credit for AFW start at 1 min (for instance, loss of normal feedwater). However, the relatively small amount of time for transfer to the safety-related ESW as the suction source, provided the transfer occurs satisfactorily, should have minimal or no observable impact upon the results. Note that the analysis for a feedline break does not assume flow initiation until 10 min (because operator action must be relied upon to isolate the faulted SG).

3.2.5 Turbine-Driven AFW Pump

3.2.5.1 Surveillance and maintenance tests/inspections

ST-7, which is conducted on an 18-month frequency, verifies that the T&T valve opens, with steam supply isolated by an upstream valve, in response to each automatic open signal (with the exception that the blackout signal is tested on only one train). The turbine is also actually started (steam supply is unisolated) three times by ST-7, with the pump discharge lined up for recirculation flow only. The three starts are for trip of the A main feed pump, trip of the B main feed pump, and trip of both main feed pumps.

ST-8 is a quarterly test of the AFW TDP. The test is conducted with the pump discharge lined up for recirculation flow only. This test is conducted to fulfill the requirements of Tech Spec Surveillance Requirements 4.0.5 and 4.7.1.2.a.2. Temporary ultrasonic flowmeters are used to measure flow through the pump miniflow line (there is no permanent miniflow line flow instrumentation). The T&T valve is opened to start the turbine by operation of the valve's control switch at the MCB, and the pump is run with only its recirculation flowpath available. Pump speed for the test is the normal operating speed of 3970 rpm. The established TDP in-service test acceptance criteria are as follows:

Parameter	Acceptable	Alert	Required action
Suction pressure, psia	≥11	NA	<11
Pump delta-P, psid	1194.6 to 1310.2	1183 to 1194.6 and 1310.2 to 1323.0	<1183 and >1323
Flow rate, gal/min	47.1 to 62.3	39.3 to 47.1 and 62.3 to 66.2	<39.3 and >66.2
Horizontal vibration, mils	0 to 1.44	1.44 to 2.16	≥2.16
Vertical vibration, mils	0 to 1	1.0 to 1.5	≥1.5

Note that the suction pressure acceptance criteria are specified in psia vs psig. This appears to be inconsistent with the Tech Spec allowable low-suction pressure setpoint of 13.9 psig.

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST Program. Valve stroke time for the T&T valve, based on remote (MCB) indication, is measured quarterly. The test is conducted with steam isolated (MOV-9 closed). Stroke time is measured from closed to open by holding the valve handswitch to OPEN. The maximum allowable stroke time for the T&T valve is 19 s.

ST-15 is conducted at shutdown, as a part of the Pump and Valve IST Program. Its intent is to full stroke several check valves, including TDP discharge check valves and steam supply check valves. Full stroking is demonstrated by verifying $\geq$220 gal/min to each SG with only the TDP running. This also provides an indication of TDP performance, since the procedure requires delivery of $\geq$220 gal/min to each SG simultaneously, but total pump flow and developed head are not recorded. SG pressure is not recorded, but the procedure specifies that the TDP-related check valves be stroked with steam pressure >842 psig.

ST-21 is an engineered safety features (ESF) response time test in which the response times for the TDP following main feed pump trip signals (performed in ST-7) are tabulated. A reference response time from signal initiation until the T&T valve begins to open (valve stem limit switch "ac" contacts close) is also determined.

ST-22 is an ESF response time test in which response times determined from numerous supporting tests are compiled and compared with allowable values. The response times for starting the TDP following an SI signal, a low-low SG level signal, an SB signal, and the main feed pump trip signals are tabulated. The time interval measured is the time from start signal generation until the pump discharge pressure stabilizes.

Note that the TDP is actually started, for response time measurement purposes, only in response to the main feed pump trip signals (see discussion under ST-7 and -21). Response times for various portions of the automatic initiation circuits are recorded in procedures MI-2 and -3 and ST-21 and are coordinated in ST-22 to determine total channel response times. Also note that the T&T valve is not opened, nor verified to open, for the low-low SG and SB signals.

ST-27 is a calibration procedure for the AFW turbine controls and is conducted on a refueling frequency. The test performs the following T&T valve-related checks:

1. The mechanical trip is manually actuated using the local trip lever. The open coil circuit of the valve is verified to be interrupted. The mechanical trip is manually reset, and restoration of the open coil circuit is verified.
2. The stem-actuated limit switch that provides initiation of the governor control ramping function is verified to close when the valve is 1/8 to 1/4 open. Total stroke length is also verified.
3. A calibration of the speed sensor that is used for indication and for the electronic overspeed trip is performed. A signal generator is used to allow the calibration to be performed without the turbine operating. The electronic overspeed trip point is verified (using the signal generator).

The test also performs a number of checks related to the governor and governor control circuit, including the following:

1. Resistance of the electromagnetic speed pickups for the turbine is checked.
2. A full governor control loop calibration is performed. This calibration includes the control speed sensor, RGSC, and the speed setting potentiometer. Most aspects of the calibration are performed with the turbine idle.

3. An actual start of the turbine is conducted to verify that the turbine comes up to 2200 rpm with the minimal flow demand signal and then controls at 3970 rpm at the full-flow demand signal. Note that the speed feedback portion of the circuitry is deleted for this portion of the test. With the turbine operating, the turbine is manually tripped using the mechanical trip lever.
4. Following resetting of the turbine trip device and reconnecting of the lifted speed feedback leads, the turbine is verified to "quick start" and come up to normal operating speed (3970 rpm) in 15 +2/-1 s.

Note that the starts of the turbine for ST-27 are done with only the miniflow recirculation flow path available.

MI-2 and -3 are a series of instrument maintenance procedures that determine response times for most reactor protection and ESF circuits, including portions of the TDP actuation circuits. The various portions of the ESF response time for the T&T valve are determined. The times are compiled in ST-22.

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators that is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting of the limit switch positions, according to the MI-11.2 series; measurement of resistance to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6 is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, which can be set based either on valve travel measurement or the number of handwheel turns, are set as follows:

1. Open limit switch: Set to allow valve to open to within 98 to 99% of full travel (the open limit switch is initially set at ~90% of full travel, then the valve is stroked electrically and valve travel measured, and the open limit switch setting is modified as necessary to achieve the 98 to 99% travel).
2. Close limit switch: Set to allow valve to close to within 99 to 100% of full travel (but with the limit switch set to open at no greater than 98% of full travel).

While not part of a formal procedure (rather, based on an operations group instruction letter), auxiliary operators check the temperatures of the pump discharge lines once per shift for evidence of backleakage of main feedwater. This monitoring is performed in response to IE Bulletin 85-01[3] and Generic Letter 88-03.[4]

3.2.5.2 Frequency of test operation

The T&T valve is stroked according to the following test procedures. Note that the turbine is not started by all tests because upstream steam supply valves are closed before stroking the T&T valve.

Procedure	Number of T&T full strokes/pump starts	Frequency
ST-3	4[a]/0	Refueling
ST-6	1/0	Refueling
ST-7	11/3	Refueling
ST-8	2/2	Quarterly
ST-11 and -13	1/0	Quarterly
ST-15	2/2	Hot standby (≤quarterly)[b]
ST-25	1/0	Monthly
ST-27	4/2	Refueling
MI-2A and -2B	1/0	Refueling[c]
MI-3A and -3B	1/0	Refueling[c]

[a] Estimated; the procedure does not identify any stroking, but multiple signals that cause valve opening are created.

[b] It is assumed that this test is performed twice per year.

[c]The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related T&T full strokes per year: 43.
Total estimated test-related turbine starts per year: 15.

3.2.5.3 Relevant operating instructions

OP-1 is the AFW system operating procedure. It includes the following guidance:

1. A precaution states that the AFW pumps should be run on recirculation flow (as opposed to stopping and starting the pumps) during conditions when SG demand is low to avoid hanger damage and to extend motor life. Another precaution stipulates that AFW should be batched at ≃75 gal/min (under manual LCV control) to each SG to prevent vibration damage and inadvertent swapover from the CST to ESW suction, as well as to prevent SG nozzle cracking.
2. Following pump start, the pump is inspected locally (no specific direction provided for the inspection).
3. A precaution states that the TDP should not be operated at <2200 rpm (the turbine idle speed). Although not specified in the procedure, the rationale behind this limitation is to prevent the rotational speed from approaching the TDP's first critical speed, calculated by the vendor to be 1900 rpm.
4. A precaution states that the pump discharge lines should be ≤125°F. This precaution is included to ensure against backleakage binding of the pumps. Note that Plant A is probably less susceptible to backleakage than many other plants because its LCVs are normally closed (some plants have only check valves between the pumps and the SGs or main feed lines).
5. A precaution states that when admitting steam to a cold line, the steam supply valve should be cracked manually to warm the line slowly to prevent hammering the line.

OP-1 also provides valve and breaker lineup and control information for system operations. The valve checklist specifies that the T&T valve is to be "Closed and Operable", and that it is latched and the mechanical overspeed trip is reset. The procedure provides directions on starting up the TDP from the main control room and locally. It is noted that the GV will fail open on loss of control power and that turbine speed can be controlled locally by manually operating the T&T valve. The procedure specifies that the T&T valve should be positioned to maintain the pump discharge pressure 100 psi greater than the steam supply pressure if so operated.

The procedure includes a note that an auxiliary power supply to the T&T valve is available but does not include directions on how to place it into service, nor does it include the normal position for the manual transfer switch.

The flow controller for the GV control circuit is specified to be in "AUTO," with its setpoint at 100% (provides a flow demand signal to the governor RGSC that is equivalent to 880 gal/min).

Another section of the OP advises that if the turbine trips on overspeed because of the flow controller failing to control flow automatically, the controller should be placed in manual and the output set at 20% before restarting.

GOP-1, -2, and -3 include some of the same precautions relative to operation of the TDP.

3.2.5.4 Comments

1. Several accident demand conditions, as well as support functions associated with the T&T valve, are not verified by periodic testing:

   a. Bypassing of the valve thermal overload switches is not verified. (The system design causes the thermal overload switches for the T&T valve to be bypassed by contacts that are actuated by all safety-related starts of the TDP.)
   b. The automatic steam supply transfer, which is built into the design to allow the turbine to operate in the event that its normal steam supply source is unavailable, is not verified by testing. This automatic transfer includes an auto-closure and a subsequent auto-open of the T&T valve. There are several tests in which the automatic steam supply transfer should occur (although steam is isolated from the T&T valve by MOV-9 and -10 during the tests), for example, ST-3A and -3B and ST-7. However, there is no note or precaution in the procedures that the automatic transfer will occur, nor is there verification that the transfer does, in fact, occur. Several potential sources of failure are not checked in conjunction with the steam supply transfer. In addition, some components that are checked, for instance, the T&T valve motor, are more seriously challenged by the back-to-back stroking that is required.
   c. Proper setting and functioning of the following stem position limit switches are not verified by surveillance testing:

      - The switch that results in automatic closure of SG BDIVs and provides the permissive to allow automatic transfer to the alternate steam supply source. (Also note that there are several relays that must energize to cause these functions to occur which are likewise not checked.)
      - The switch that causes the TDP room ventilation fan to start.
      - The switch that causes the T&T valve operator to automatically drive to the shut position following an electronic overspeed trip.

2. The T&T valve is not included in the Tech Spec list of valves for which verification of thermal overload protection operability is required (and therefore the settings of its thermal overload heaters/switches are not checked by a surveillance test). Note that, according to comment 1a, the bypassing of the thermal overload switches is also not verified for the T&T valve. If the bypassing of the thermal overload switches were verified, the thermal overload setting would be of less significance.
3. Automatic operation of the T&T valve closing coil to drive the motor to shut, thereby relatching the motor to the valve (and allowing the valve to automatically reopen, if the open signal is still present), following an electronic overspeed trip is not verified.
4. The electronic overspeed trip setpoint is tested under nonoperating conditions (turbine not running). While the ability to trip the turbine using the mechanical trip lever is performed in ST-27, the mechanical trip setpoint is not tested periodically. Therefore, no test verifies that the electronic overspeed trip will precede, and thereby avoid, the mechanical overspeed trip. (Note that an electronic overspeed trip is preferred, from an operational standpoint, because the mechanical overspeed trip requires local resetting.)
5. Only one train of the SB signal is verified to cause opening of the T&T valve in ST-7. The test that is conducted is performed by jumpering contacts, as opposed to simulating the signal (e.g., by deenergizing both sets of initiating relays). The train to be tested is left to operator discretion. Although both trains of SB relays (the relays that cause closure of the contacts noted to be jumpered above) are tested as a part of response time testing for the MDPs (in ST-3A and -3B), the T&T valve is not verified to open.
6. With the exception of the testing of DCVs which is performed in ST-15, the test-related runs of the TDP are performed with only the miniflow recirculation flow path available. There is no monitoring of the *pump/turbine* capability other than with minimum flow, plus the incomplete (only flow is recorded) indication provided by ST-15.
7. The tests for the TDP, as allowed by Tech Specs, are not required unless the steam supply pressure is >842 psig (see Tech Spec Surveillance Requirement 4.7.1.2.a.2). However, as indicated in the "Basis" section for Tech Spec 3/4.7.1.2, the AFW system is depended upon to provide flow to the SGs until the RCS reaches 350^{o}F. Assuming no temperature differential between the RCS and the secondary side of the SGs, the corresponding saturation steam pressure would be ~120 psig. There is no testing of the TDP's ability to operate properly at reduced steam supply pressures.

3.2.6 Pump Miniflow Check Valves: C-6, -8, and -10

3.2.6.1 Surveillance and maintenance tests/inspections

ST-8 and -9 are quarterly tests in which the AFW pumps are run in recirculation only. The MCVs are deemed to be operable in these procedures if recirculation flow, as measured by the use of a strap-on ultrasonic flowmeter, is at least 47 gal/min for the TDP and 29/27 gal/min for MDPs A/B.

3.2.6.2 Frequency of test operation

The MDP MCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-3A and -3B	5	Refueling
ST-6	5	Refueling
ST-9	1	Quarterly
ST-15	1	Hot standby (≤quarterly)[a]
ST-16	1	Refueling
MI-2A and -2B	1	Alternate refueling[b]
MI-3A and -3B	1	Alternate refueling[b]

[a] It is assumed that this test is performed twice per year.

[b] The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related full strokes per year: The above test frequency information would yield about 14 full strokes per year; however, the MDPs are used for protracted periods during startups and shutdowns, with varying flow rates, with the dominant amount of time spent at relatively low flow rates or in recirculation flow only. Thus, the valves are stroked much more frequently than indicated by testing. Note that "full strokes" refers to conditions when the flow rate through the valves is at or near the maximum that occurs, not necessarily a condition where the check valve is fully open.

The TDP MCV is stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-7	3	Refueling
ST-8	2	Quarterly
ST-15	2	Hot standby (≤quarterly)[a]
ST-27	2	Refueling

[a] It is assumed that this test is performed twice per year. Also note that the TDP is not assumed to already be operating when ST-15 is performed, as are the MDPs.

Total estimated test-related full strokes per year: 15. The only time the valves would be likely to experience full stroking would be during testing, although there might be some infrequent operational demands that would result in substantial, if not design-basis, flow rates through the valves. Note that "full strokes" refers to conditions when the flow rate through the valve is at or near the maximum that occurs, not necessarily a condition where the check valve is fully open.

3.2.6.3 Comments

The flow rates through the minimum flow lines are substantially less than current vendor-recommended minimum flow for both the MDPs and TDP. At the minimum acceptable flow rates through the miniflow lines of 29/27 gal/min for the MDPs and 47 gal/min for the TDP, the line velocities are 6 and 11 ft/s, respectively. Under these conditions, and particularly in light of the fact that the miniflow orifice is immediately upstream of the MCVs, disk oscillation would be expected.

The measurement of flow through the lines is by a strap-on ultrasonic flowmeter. The test procedures do not specify exactly where to place the flowmeter. The repeatability and accuracy of the ultrasonic flowmeter indication, in light of the lack of specification of location as well as inherent instrumentation inaccuracy, would be expected to be relatively poor.

3.2.7 Common Miniflow Check Valves: C-1 and -2

3.2.7.1 Surveillance and maintenance tests/inspections

ST-9 is a quarterly test in which the MDPs are run in recirculation only. The CMCVs are deemed to have been partially stroked in this procedure if recirculation flow, as measured by the use of a strap-on ultrasonic flowmeter, is at least 27 gal/min (MDP B).

ST-16 is performed once every 2 years for the specific purpose of demonstrating operability of the CMCVs. The test is performed by operating both MDPs and the TDP with only the recirculation flow path to the CST available. Flow rates are not recorded.

3.2.7.2 Frequency of test operation

The CMCVs are stroked according to the following procedures:

Procedure	Number of full/partial strokes	Frequency
ST-3A and -3B	10P	Refueling
ST-6	10P	Refueling
ST-7	3P	Refueling
ST-8	2P	Quarterly
ST-9	2P	Quarterly
ST-15	3P	Hot standby (≤quarterly)[a]
ST-16	1F	Refueling
ST-27	2P	Refueling
MI-2A and -2B	1P	Alternate refueling[b]
MI-3A and -3B	1P	Alternate refueling[b]

[a] This test is assumed to be performed twice per year.

[b] The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related strokes per year: The above test frequency information would yield about 39 partial strokes and 1 full stroke per year; however, the MDPs are used for protracted periods during startups and shutdowns, with varying flow rates, with the dominant amount of time spent at relatively low flow rates or in recirculation flow only. Thus, the valves are partially stroked much more frequently than indicated by testing. Note that "full strokes" refers to conditions when the flow rate through the valve is at or near the maximum that occurs, not necessarily a condition where the check valve is fully open.

3.2.7.3 Comments

Running a number of pumps in recirculation simultaneously, as is done in ST-16, does not provide a reliable indication of operability of the check valves, because flow is not measured. To demonstrate required operability, the actual flow of each pump (or at a minimum, the combined flow through the CMCVs) should be measured.

Note that the flow velocities through the CMCVs are extremely low, even under conditions where all three AFW pumps are running simultaneously. An estimate of velocity through only one CMCV and through both of the parallel CMCVs for various nominal flow rates is provided below:

Flow (gal/min)	Number of pumps running	Velocity (ft/s) one CMCV open	Velocity (ft/s) both CMCVs open
25	One MDP	1	0.6
40	TDP	2	1
90	All pumps	4	2

The fact that the conditions under which these valves would be stroked from shut to open would normally be at very low velocities (including the ST-16 test, in which the maximum expected flow is passed through the valves) suggests that the valve wear rate, as a function of service hours, would be fairly high.

3.2.8 Pump Discharge Check Valves: C-7, -9, and -11

3.2.8.1 Surveillance and maintenance tests/inspections

ST-15, which is performed during each entry into hot standby conditions, demonstrates that the pumps are able to deliver design-basis flow to the SGs. The test thereby demonstrates that the DCVs stroke open sufficiently to allow the required flow to pass through them. The total flow rates to the SGs must be $\geq$440 gal/min for the MDPs and $\geq$880 gal/min for the TDP.

ST-28, which is performed on a refueling frequency, calls for the disassembly and inspection of several check valves. Note that this ST is not performed to meet a specific Tech Spec surveillance requirement and is not required by the ASME Section XI program but is performed as a consequence of the San Onofre water hammer event (see NUREG-1190[1] and IE Notice 86-09[2]). The valves are organized in groups of four. One valve out of each group is disassembled and inspected each refueling outage; so each valve will be inspected about every 6 years. If a valve fails to meet the acceptance criteria (see below), all other valves in the group are to be inspected during the same outage. The DCVs, along with the TDP SCV, make up one group of valves to be disassembled and inspected in ST-28.

Acceptance criteria are

1. all internal parts in place and showing no signs of abnormal wear;
2. all internal locking devices, including tack welds, in place and in good condition; and
3. all internal surfaces in good condition and showing no signs of abnormal wear.

While not part of a formal procedure (rather, based on an operations group instruction letter), auxiliary operators check the temperatures of the pump discharge lines once per shift for evidence of backleakage of main feedwater. This monitoring is performed in response to IE Bulletin 85-01[1] and Generic Letter 88-03.[2]

3.2.8.2 Frequency of test operation

The MDP DCVs are stroked according to the following procedure:

Procedure	Number of full strokes	Frequency
ST-15	1	Hot standby (≤quarterly)[a]

[a] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 2. The only time the valves would be likely to experience full stroking would be during testing, although there might be some operational demands, such as total or partial loss of feedwater that would result in substantial, if not design-basis, flow rates through the valves. Note that since the MDPs are used during startup and shutdown periods, their DCVs would be partially stroked frequently since the pumps are used to maintain SG level.

The TDP DCV is stroked according to the following procedure:

Procedure	Number of full strokes	Frequency
ST-15	2	Hot standby (≤quarterly)[a]

[a] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 4. The only time the valves would be likely to experience full stroking would be during testing, although there might be some infrequent operational demands that would result in substantial, if not design-basis, flow rates through the valves.

3.2.8.3 Relevant operating instructions

Because the turbine-driven AFW pump would seldom be used to support startup/shutdown evolutions, the normal operating procedurés primarily affect the MDP DCVs. The precautions noted in section 3.2.1.3 (for the pump SCVs) also apply to the DCVs.

3.2.8.4 Comments

The function of preventing reverse flow from either a parallel AFW pump or from main feedwater is accomplished by several valves, including the DCVs. The disassembly and inspection performed, as well as the full-flow testing that is performed, help ensure that the valve strokes open freely. The disassembly and inspection also provide some level of assurance that the valve will not allow an extreme amount of reverse flow. There is no testing which attempts to verify that each specific valve keeps reverse flow to less than some acceptable value. However, as long as the *series* of valves, including, for example, a closed LCV and its downstream check valve as well as the DCV, are demonstrated to prevent reverse flow, it is not viewed as particularly critical that the leaktightness of a specific valve be known.

At the maximum flow required for test conditions (220 gal/min per SG in ST-15), the velocity through the MDP DCVs is ~6 ft/s. At the flow rate associated with "batching" the SGs during shutdown periods (75 gal/min per SG, or 150 gal/min total, per OP-1 and GOP-1 and -2), the velocity is ~2 ft/s. These velocities are very low, especially considering the location of the DCVs (see Fig. 3.5), and disk oscillation would be expected.

3.2.9 Motor-Driven AFW Pump Level Control Valves: LCV-1/1A, -3/3A, -5/5A, and -7/7A

3.2.9.1 Surveillance and maintenance tests/inspections

ST-4, which is conducted on an 18-month frequency, is a channel calibration procedure. The procedure performs a loop calibration on the SG-level instrument loops, from the level transmitters all the way through to the valves themselves. The procedure verifies valve position as a function of demand throughout the demand range. It verifies that the air supply pressures for the valve operators and the valve I/P converters are correct. It also verifies that the setpoints for the pressure switches that cause the control to transfer from the MDLCVs to the BMDLCVs (PS-1, -3, -5, and -7) are proper. The check of the pressure switch setpoints is redundant to a check performed in ST-18.

ST-6, which is performed every 18 months, verifies that the MDLCV and BMDLCV controllers switch from manual to automatic and that the automatic controllers cause the valves to open/close in response to SG level below/above setpoint, in response to simulation of each automatic AFW actuation signal. The test is performed with the manual isolation valves downstream of the LCVs closed, thereby preventing delivery of flow to the SGs. The portion of the test that simulates an SB signal does so by jumpering two sets of contacts (operated by the two undervoltage relays) which are normally open but go closed when the associated 6.9-kV bus experiences an undervoltage condition. (Note that the relays which deenergize to cause the contacts to close are verified to cause the MDPs to start in MI-3, but the specific contacts that affect the MDLCVs and BMDLCVs are not verified to operate when the relays deenergize.)

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST program. Valve stroke times for the MDLCVs and the BMDLCVs are checked, using remote (MCB) position indication, on a quarterly basis. Valve stroke times, based on local observation of valve stem movement, are checked every 2 years and compared with stroke times recorded remotely. Local position is verified to agree with remote position indication every 2 years. The maximum allowable stroke times identified for the MDLCVs and the BMDLCVs are as follows:

MDLCV	Maximum stroke time (s)	BMDLCV	Maximum stroke time (s)
LCV-1	14.4	LCV-1A	25.2
LCV-3	11.2	LCV-3A	25.3
LCV-5	15.6	LCV-5A	14.0
LCV-7	10.2	LCV-7A	15.6

The stroke time of an MDLCV is checked by first putting the valve handswitch in MANUAL BYPASS and ramping the BMDLCV to full open. (Under these conditions, the MDLCV solenoid is energized, keeping it closed, while its controller, which is used for both the MDLCV and the BMDLCV, provides a maximum open signal.) The handswitch is then placed in the MANUAL position, which deenergizes the MDLCV solenoid, causing the MDLCV to open. Stroke time is measured during this open stroke. A similar sequence is used for stroke time testing the BMDLCVs, except that the handswitch is transferred from MANUAL to MANUAL BYPASS to initiate the stroke.

ST-20 is a test in which the response times of various portions of the AFW actuation circuitry are checked. This test measures the times in conjunction with actual equipment operations that occur when ST-6 is conducted. The times that are applicable to the

MDLCVs and BMDLCVs are the times from main feed pump trip until energization of relays that result in the transfer of the valve controllers from manual to automatic.

ST-22 is an ESF response time test in which the response times for the MDLCVs are measured. The times are measured from a simulated low-level signal input to the level controller from the level transmitter (note that this is not the same as the low-low SG level signal that causes AFW actuations to occur) until the MDLCVs are full open. The times are actually measured in MI-2; in ST-22, the valve stroke response times from MI-2 are added to the relay response times and to other portions of the channel response time (logic and master relay response time) to calculate the total response time of the MDLCVs. The total response times for each of the MDLCVs, as well as the TDLCVs, the MDPs, and the TDP, are compared; and the maximum time associated with any of these components is designated as the ESF response time for AFW.

ST-24, which is performed monthly, verifies that the controllers for the MDLCVs and BMDLCVs respond appropriately to level deviation signals. If the test is performed during a time when the applicable pump is being used to maintain SG level (during shutdown), the test will use both valve position change and observed flow to verify stroking. If the applicable pump is not in service to maintain SG level, the pumps are simulated to be running, and valve operability is based upon indicated position change in response to level deviation signals. The latter (pump not in service for level maintenance) will be the normal test condition.

Note that this test verifies that the controller responds to transfer of the MCB switches from MANUAL to AUTO (with a preestablished level deviation) and also verifies controller response to adjustment of the automatic control setpoint at the ACP.

MI-2 is a response time procedure, performed once per refueling outage (one train is performed each outage), in which the time required for each MDLCV to stroke from closed to open in response to a simulated low SG level signal input to the valve controller is measured. The time is used in ST-22 to determine total AFW actuation response time. MI-2 also checks the response time for relays that result in the transfer of the valve controllers from manual to automatic.

MI-7 is used to verify the time delay relay associated with the automatic transfer from the MDLCVs to the BMDLCVs times out at 15 s. The procedure does not actuate any equipment; it only verifies relay timing. There is no designated frequency of testing.

3.2.9.2 Frequency of test operation

The MDLCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-4	1	Refueling
ST-6	6	Refueling
ST-10 and -13	1	Quarterly
ST-15	1[a,b]	Hot standby ($\leq$ quarterly)[c]
ST-24	1	Monthly
MI-2A and -2B	1[a]	Alternate refueling[d]

[a] Only the MDLCVs are stroked (the BMDLCVs are not).
[b] This is the only *test* in which the valves open to allow flow.
[c] It is assumed that this test is performed twice per year.
[d] Each MDLCV is stroked once every other refueling outage.

Total estimated test-related full strokes per year: The above test frequency information would yield about 23 full strokes per year for the MDLCVs and 21 for the BMDLCVs;

however, both the MDLCVs and the BMDLCVs would be used routinely to support normal plant operation during startup and shutdown periods. Multiple partial or full strokes would occur during these evolutions.

3.2.9.3 Relevant operating instructions

OP-1, which is the AFW system operating procedure, specifies that the level controllers at the ACP be set for 33%.

The procedure also includes the following practices or requirements related to the MDLCVs and BMDLCVs:

1. For startup of an MDP, the procedure advises the operator to close all LCVs, if time permits, and to control SG level by manually throttling the associated LCVs.
2. For MDLCV manual local operation, the procedure provides directions as to the physical location of the valves, cautions the operator to maintain flow from an MDP to <200 gal/min in Mode 5 or 6, and has the operator maintain level by throttling either the upstream or downstream isolation (gate) valves. A note is provided advising the operator that the MDLCVs fail open and the BMDLCVs fail closed on loss of power or air.
3. A precaution stipulates that AFW should be batched at ~75 gal/min (under manual LCV control) to each SG to prevent vibration damage and inadvertent swapover from the CST to ESW suction as well as to prevent SG nozzle cracking.

3.2.9.4 Comments

All testing is performed with the MDLCV control switches in MANUAL/MANUAL BYPASS. The normal, standby switch position is AUTO. With the switches in MANUAL, the LCV solenoids will be continuously deenergized, and therefore valve position will be controlled by the controller only. In normal system configuration, the LCV solenoids are energized (and the LCVs are therefore closed) and deenergize when the associated pump starts, thereby allowing the LCVs to modulate. The circuit change that causes the solenoids to transfer from the energized to the deenergized state (opening of pump breaker auxiliary contacts 52S/b) is not demonstrated.

The simulation of an SB signal to verify responses of the MDLCVs and BMDLCVs is done by jumpering the blackout contacts that are normally open, but close in response to loss-of-bus-voltage conditions. The contacts that are jumpered are the contacts that cause the TDP to start as well as enabling the TDLCVs, MDLCVs, and BMDLCVs to perform their required automatic level control functions. Although the blackout relays are verified to deenergize to cause other contact operations (associated with the start of the MDPs) in other procedures, the contacts that are jumpered for testing simulation purposes are not verified to operate properly (close when the relays deenergize).

The automatic transfer from MDLCV to BMDLCV control is not demonstrated. The pressure switches that initiate the transfer are verified to close at the correct setpoint (in ST-4), but the pump breaker contacts (52S/a), which provide another portion of the auto transfer permissive, as well as the relay and associated contacts that effect the transfer, are not verified to operate. The principal significance of not testing these components is that in the event of a faulted SG, failure of the faulted SG's MDLCV to transfer over to BMDLCV would result in continuing flow through the larger valve to the faulted SG.

The ability of the ACCIDENT RESET switch position to transfer the controller back to manual control in the presence of an accident signal is not demonstrated. Although the ACCIDENT RESET switch position is used several times in the surveillance tests, the simulated accident signal is always removed first, thereby rendering the transfer to ACCIDENT RESET meaningless. The primary importance of being able to transfer to manual control is to provide the operator with the capability of dealing with either a situation where the controller(s) malfunctions in AUTO or where a faulted SG condition exists and flow to the faulted SG needs to be isolated (which would not occur automatically, since a low SG level condition would exist). Note that automatic transfer from MDLCV to BMDLCV control *should* occur when the downstream pressure is <400 psig; however, this is also not demonstrated to occur.

In addition to the fact that the ACCIDENT RESET switch is not demonstrated, there exists a design condition for which the MDLCVs cannot be reset to manual control. When the plant has been operating at >80% load, a main feed pump trip will result in automatic start of the AFW pumps. Even for automatic starts of the AFW pumps from other sources (such as SI) which occur first, the feed pump trip start signal would also be generated. A single contact, which is operated by a nonsafety-grade pressure switch that senses HP turbine impulse pressure, would prevent transfer of any of the MDLCV controllers from automatic to manual without additional operator intervention (such as the lifting of leads), in the event that it sticks closed. (Note that it is set to open at <75% power.) The ability to reset the controls to manual and isolate a faulted SG within 10 min is taken credit for in the feedline and steamline accident analyses.

None of the surveillance tests that officially demonstrate the OPERABILITY of the MDLCVs put any flow through the valves; however, ST-15, which is used to demonstrate full stroking of various check valves, does demonstrate that the valves can be opened (using the manual controls) to allow ≥220 gal/min to each SG.

3.2.10 Turbine-Driven Pump Level Control Valves: LCV-2, -4, -6, and -8

3.2.10.1 Surveillance and maintenance tests/inspections

ST-4, which is conducted on an 18-month frequency, is a channel calibration procedure. The procedure performs a loop calibration on the SG level instrument loops, from the level transmitters all the way through to the valves themselves. The procedure verifies valve position as a function of demand throughout the demand range. It also verifies that the air supply pressures for the valve operators and the valve I/P converters are correct.

ST-7, which is conducted on an 18-month frequency, verifies that the TDLCV's controllers switch from manual to automatic and then open/close the valves in response to level below/above control setpoint, in response to each automatic TDP start signal (except that the blackout signal is tested on only one train). No flow is delivered in this test because downstream isolation valves are closed. All tests are conducted with the valve switches in "MANUAL" (the normal position is "AUTO").

ST-10, -11, and -13 are used to implement the ASME Section XI valve in-service testing requirements. The TDLCVs are stroked once per quarter under these procedures for remote stroke time measurement. Every 2 years, the valves are stroked for verification of consistency between local and remote stroke time measurement and position indication. No flow is delivered to the SGs in this test. The maximum allowable stroke times for the TDLCVs, as identified in ST-10, are as follows:

LCV-2: 102.6 s
LCV-4: 132.0 s
LCV-6: 126.0 s
LCV-8: 112.0 s

The valves are stroked, per ST-10, by placing the valve handswitch in MANUAL and then ramping the valve open using the manual controls.

ST-22 is an ESF response time test in which the response times for the TDLCVs are measured. The times are measured from a simulated low-level signal input to the level controller from the level transmitter (note that this is not the same as the low-low SG level signal that causes AFW actuations to occur) until the TDLCVs are full open. The times are actually measured in MI-2. In ST-22, the response times for the TDLCVs, as well as those for the MDLCVs, the TDP, and the MDPs, are compiled. The maximum time associated with any of these components is designated as the ESF response time.

ST-24 is a monthly test by which the proper responses of the automatic controller to above/below setpoint deviation signals are verified. Note that this test verifies that the controller responds to transfer of the MCB switches from MANUAL to AUTO (with a preestablished level deviation) and also verifies controller response to adjustment of the automatic control setpoint at the ACP.

MI-2 and -3 are a series of procedures that determine response times for most reactor protection and ESF circuits, including portions of the TDP actuation circuits. The various portions of the ESF response time for the TDLCVs are determined. The times are compiled in ST-22.

3.2.10.2 Frequency of test operation

The TDLCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-4	1	Refueling
ST-7	7	Refueling
ST-10 and -13	1	Quarterly
ST-15	2[a]	Hot standby ($\leq$quarterly)[b]
ST-24	1	Monthly
MI-2A and -2B	1	Alternate refueling[c]

[a] This is the only test in which flow through the TDLCVs is exhibited (the TDLCVs are opened after the TDP is started, and $\geq$220 gal/min to each SG is verified).

[b] It is assumed that this test is performed twice per year.

[c] The MI tests are performed on an alternating basis; that is, one train is tested per refueling outage.

Total estimated test-related full strokes per year: 26

3.2.10.3 Relevant operating instructions

See the discussion for the MDP LCVs (MDLCVs) under Sect. 3.2.9.3 above. The comments also apply to the TDLCVs.

3.2.10.4 Comments

A check valve is provided in the control air line upstream of the accumulator connection. The function of the check valve is to ensure that, in the event of control air loss, the air in the accumulator will be available for valve stroking. This check valve is not tested, nor is the ability of the accumulator (in the absence of continuing control air supply) to stroke the LCV demonstrated periodically.

The maximum allowable stroke times for the TDLCVs established in ST-10 appear to be very high and inconsistent with the allowable ESF response time for AFW (60 s). Also, the response time for the TDLCVs is measured under no-flow conditions. Because these are fail-closed valves, stroke times under flow conditions (vs no flow) would be expected to increase.

The automatic pipe break detection function, which isolates the TDLCV to a faulted SG, is not tested. Two sets of pressure switches (TDP pressure switches PS-10 and -11 and the pressure switches downstream of the TDLCVs: PS-14 and 15, PS-16 and -17, PS-18 and -19, and PS-12 and -13), along with relays and contacts that must change state in response to pressure switch closure, are required to operate properly in order for the automatic isolation to occur. Although both sets of pressure switches are checked to verify that the switches close at the proper pressure, the relays and associated contacts that actually cause isolation are not verified. Note that even though the TDLCVs close by design, this is not a Tech Spec required function for Plant A (faulted SG isolation is a Tech Spec requirement for some other plants).

The ability of the ACCIDENT RESET switch position to transfer the TDLCV controller back to manual control in the presence of an accident signal is not demonstrated. Although the ACCIDENT RESET switch position is used several times in the surveillance tests, the simulated accident signal is always removed first, thereby rendering the transfer to ACCIDENT RESET meaningless. The primary importance of being able to transfer to manual control is to provide the operator with the capability of dealing with either a situation where the controller(s) malfunctions in AUTO or where a faulted SG condition exists and flow to the faulted SG is not automatically isolated (note that the automatic isolation feature is not verified).

In addition to the fact that the ACCIDENT RESET switch is not demonstrated, there exists a design condition for which TDLCVs cannot be reset to manual control. When the plant has been operating at >80% load, a main feed pump trip will result in automatic start of the AFW pumps. Even for automatic starts of the AFW pumps from other sources (such as SI) which occur first, the feed pump trip start signal would also be generated. A single contact, which is operated by a nonsafety-grade pressure switch that senses HP turbine impulse pressure, would prevent transfer of any of the TDLCV controllers from automatic to manual without additional operator intervention (such as the lifting of leads), in the event that it sticks closed. (Note that it is set to open at <75% power.) The ability to reset the controls to manual and isolate a faulted SG within 10 min is taken credit for in the feedline and steamline accident analyses.

No testing is conducted in which the TDLCVs are verified to open/close automatically with their control switches in AUTO, which is the normal condition. All testing in which the valves are stroked, whether manually or by the automatic controller, is done with the valve control switch in MANUAL. The contacts that would open to deenergize the valves' solenoids with the switches in AUTO are therefore never demonstrated. (Note that the relays that operate the contacts are also not verified to operate.)

None of the surveillance tests that officially demonstrate the OPERABILITY of the TDLCVs put any flow through the valves; however, ST-15, which is used to demonstrate full stroking of various check valves, does demonstrate that the valves can be opened (using the manual controls) to allow ≥220 gal/min to each SG.

3.2.11 Level Control Valve Check Valves: C-12, -13, -14, -15, -16, -17, -18, and -19

3.2.11.1 Surveillance and maintenance tests/inspections

ST-15, which is performed during each entry into hot standby conditions, demonstrates that the pumps are able to deliver design-basis flow to the SGs. The test thereby demonstrates that the LCVCVs stroke open sufficiently to allow the required flow to pass through them. The total of flow rates to the SGs must be ≥440 gal/min for the MDPs and ≥880 gal/min for the TDP.

ST-28, which is performed on a refueling frequency, calls for the disassembly and inspection of several check valves. Note that this ST is not performed to meet a specific Tech Spec surveillance requirement and is not required by the ASME Section XI program but is performed as a consequence of the San Onofre water hammer event (see NUREG-1190[1] and IE Notice 86-09[2]). The valves are organized in groups of four. One valve out of each group is disassembled and inspected each refueling outage; so each valve will be inspected about every 6 years. If a valve fails to meet the acceptance criteria (see below), all other valves in the group are to be inspected during the same outage. The MDP LCVCVs (C-13, -15, -17, and -19) make up one group, and the TDP LCVCVs (C-12, -14, -16, and -18) make up another group of valves that are disassembled and inspected in ST-28.

Acceptance criteria are

1. all internal parts in place and showing no signs of abnormal wear;
2. all internal locking devices, including tack welds, in place and in good condition; and
3. all internal surfaces in good condition and showing no signs of abnormal wear.

3.2.11.2 Frequency of test operation

The MDP LCVCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-15	1	Hot standby (≤quarterly)[a]

[a] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 2. The only time the valves would be likely to experience full stroking would be during testing, although there might be some operational demands, such as total or partial loss of feedwater, that would result in substantial, if not design-basis, flow rates through the valves. Note that since the MDPs are used during startup and shutdown periods, their LCVCVs would be partially stroked (in manual) frequently since the pumps are used to maintain SG level. Note that "full strokes" refers to conditions when the flow rate through the valves is at or near the maximum that occurs, not necessarily a condition where the check valve is fully open.

The TDP LCVCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-15	1	Hot standby (≤quarterly)[a]

[a] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 4. The only time the valves would be likely to experience full stroking would be during testing, although there might be some occasional operational demands, such as total or partial loss of normal feedwater, that would result in substantial, if not design-basis, flow rates through the valves. Note that "full strokes" refers to conditions when the flow rate through the valves is at or near the maximum that occurs, not necessarily a condition where the check valve is fully open.

3.2.11.3 Relevant operating instructions

Because the turbine-driven AFW pump would seldom be used to support startup/shutdown evolutions, the normal operating procedures primarily affect the MDP

LCVCVs. The precautions noted in section 3.2.1.3 (for the pump SCVs) also apply to the LCVCVs.

3.2.11.4 Comments

The batch flow rate that is specified by the operating procedures for the AFW lines to the SGs during startup/shutdown (75 gal/min) corresponds to a flow velocity of 2 ft/s. This low flow rate (and complicated by the piping configuration for the "A" pump lines – see Fig. 3.7) would be expected to contribute to disk oscillation and wear.

The function of preventing reverse flow from either a parallel AFW pump or from the main feedwater system is accomplished by several valves, including the LCVCVs. The disassembly and inspection performed, as well as the full-flow testing that is performed, help ensure that the valve strokes open freely. The disassembly and inspection also provide some level of assurance that the valve will not allow an extreme amount of reverse flow. There is no testing which attempts to verify that each specific valve keeps reverse flow to less than some acceptable value. However, as long as the series of valves, including, for example, the combination of a closed LCV, the associated LCVCV, and the pump discharge check valve, are demonstrated to prevent reverse flow, it is not particularly critical that the leaktightness of a specific valve be known.

The requirement to inspect the TDP LCVCVs at the same frequency as the MDP LCVCVs does not appear supportable from the standpoint of susceptibility to operationally induced wear. It would appear that less emphasis on the TDP LCVCVs would be reasonable (perhaps only disassemble and inspect one valve every other refueling outage).

3.2.12 SG B and C AFW to Main Feed Check Valves: C-21, -22, -24, and -25

3.2.12.1 Surveillance and maintenance tests/inspections

ST-15, which is performed during each entry into hot standby conditions, demonstrates that the pumps are able to deliver design-basis flow to the SGs. The test thereby demonstrates that the MFCVs stroke open sufficiently to allow the required flow to pass through them. The total of flow rates to the SGs must be $\geq$440 gal/min for the MDPs and $\geq$880 gal/min for the TDP.

ST-28, which is performed on a refueling frequency, calls for the disassembly and inspection of several check valves. Note that this ST is not performed to meet a specific Tech Spec surveillance requirement and is not required by the ASME Section XI program but is performed as a consequence of the San Onofre water hammer event (see NUREG-1190[1] and IE Notice 86-09[2]). The valves are organized in groups of four. One valve out of each group is disassembled and inspected each refueling outage; so each valve will be inspected about every 6 years. If a valve fails to meet the acceptance criteria (see below), all other valves in the group are to be inspected during the same outage. The MFCVs make up one group of valves that are disassembled and inspected in ST-28.

Acceptance criteria are

1. all internal parts in place and showing no signs of abnormal wear;
2. all internal locking devices, including tack welds, in place and in good condition; and
3. all internal surfaces in good condition and showing no signs of abnormal wear.

3.2.12.2 Frequency of test operation

The MFCVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-15	3	Hot standby (≤quarterly)[a]

[a] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 6. The only time the valves would be likely to experience full stroking would be during testing, although there might be some operational demands, such as total or partial loss of feedwater, that would result in substantial, if not design-basis, flow rates through the valves. Note that since the MDPs are used during startup and shutdown periods, the MFCVs would be partially stroked frequently since the pumps are used to maintain SG level.

3.2.12.3 Relevant operating instructions

See the precautions noted in section 3.2.1.3 (for the pump SCVs). The MFCVs would be most frequently exposed to flow rates of ~75 gal/min.

3.2.12.4 Comments

The velocity at the MFCVs during the "batching" of AFW to the SGs at 75 gal/min would be about 2.4 ft/s, which is less than that required to fully open the MFCVs. In addition, as noted previously, disk oscillation due to turbulence would be expected in light of the piping configuration. However, the combination of disassembly and inspection and flow monitoring appear to provide reasonable assurance that degradation of these valves would be detected and corrected.

3.2.13 Main Feedwater Check Valves: C-20, -23, -26, and -27

3.2.13.1 Surveillance and maintenance tests/inspections

ST-29, which is performed during cold shutdown with the SGs depressurized, verifies closure of the FWCVs by monitoring the extent of backleakage of water from the SGs. The test acceptance criteria allow a leak rate of about 16 gal/min.

ST-28, which is performed on a refueling frequency, calls for the disassembly and inspection of several check valves. Note that this ST is not performed to meet a specific Tech Spec surveillance requirement and is not required by the ASME Section XI program but is performed as a consequence of the San Onofre water hammer event (see NUREG-1190[1] and IE Notice 86-09[2]). The valves are organized in groups of four. One valve out of each group is disassembled and inspected each refueling outage; so each valve will be inspected about every 6 years. If a valve fails to meet the acceptance criteria (see below), all other valves in the group are to be inspected during the same outage. The FWCVs make up one group of valves to be disassembled and inspected in ST-28.

Acceptance criteria are

1. all internal parts in place and showing no signs of abnormal wear;
2. all internal locking devices, including tack welds, in place and in good condition; and
3. all internal surfaces in good condition and showing no signs of abnormal wear.

3.2.13.2 Frequency of test-related operation

The FWCVs are not stroked for test purposes. The normally open valves would close when normal feedwater flow to the SGs is terminated, either during routine plant shutdown or following certain transients, such as loss of feedwater or feedwater isolation.

3.2.13.3 Comments

As noted above, the test that checks for backleakage (ST-29) allows up to about 16 gal/min seat leakage under depressurized conditions where the only driving force is the elevation head associated with the water level in the SGs.

Assuming that (1) the reverse flow rate through the check valve is proportional to the square root of the pressure drop and that (2) the valve disk/seat geometry is not affected by the difference between test and demand pressure and temperature conditions, the 16 gal/min allowable backleakage under depressurized conditions would correspond to about 130 gal/min per SG at the pressure of the lowest SG safety valve. This appears to be unacceptable.

3.2.14 Feedwater Isolation Valves: FWIV-1, -2, -3, and -4

3.2.14.1 Surveillance and maintenance tests/inspections

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST program. Valve stroke times for the FWIVs, based on remote (MCB) indication, are measured quarterly. Stroke time is measured by turning the handswitch to closed and measuring the time until the valve-open indicating light is off and the closed indicating light is on. The maximum allowable stroke time for the FWIVs is 7.5 s.

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators which is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting of the limit switch positions, according to MI-6B; measurement of resistance from each phase to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6B is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, which can be set based either on valve travel measurement or the number of handwheel turns, are set as follows:

1. Open limit switch: Set such that the valve will open to within 98 to 99% of full travel, where "full travel" is the distance from valve to seat contact (closed) to backseat contact (open).
2. Close limit switch: Set such that the valve will close to within 99 to 100% of full travel.

3.2.14.2. Frequency of test-related operation

The FWIVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-3A and -3B	4	Refueling
ST-10 and -13	1	Cold shutdown[a]
ST-29	1	Cold shutdown[a]

[a] Assumed to occur once per year (in addition to refueling outages).

Total estimated test-related full strokes per year: 5

3.2.14.3 Relevant operating instructions

From an AFW perspective, the operating procedures of importance are the emergency operating procedures. Emergency procedures require early verification of closure of the FWIVs. The emergency procedure that is initially used for normal posttrip purposes, EOP-1, "Reactor Trip or SI," has the operator verify that the FWIVs (and upstream main feed control valves) are closed as one of the early actions (Step 7). Main feed isolation is also verified in step 3 of EOP-2, "Reactor Trip Response." EOP-2 would be transitioned into from EOP-1 following a reactor trip without safety injection being required. While the checks in these two procedures are the primary means by which the operator is instructed to ensure that the FWIVs are closed, main feed isolation is also verified in other procedures that may be transitioned into as conditions dictate (e.g., step 2 of E-2, "Faulted SG Isolation").

3.2.14.4 Comments

The power supplies for the motor-operated FWIVs at Plant A are not strongly tied to the AFW system. For instance, the FWIV to SG B is operated by a motor powered off of a "B" train bus, while SG B is fed by MDP A, which is powered from an "A" train bus. A similar circumstance exists for the SG C FWIV (powered from "A" train) and the AFW pump used to feed SG C ("B" pump). Also, as at most plants, the signals that automatically start the AFW pumps do not provide a close signal to the FWIVs.

From a feedline break perspective, the function of these valves is fairly important. The San Onofre event is a good example of the importance that these valves have in assuring that AFW is actually delivered to the SGs. The FWIVs are not leak-rate checked; however, the fact that they are gate valves should minimize the probability of excessive seat leakage.

3.2.15 SG Blowdown Isolation Valves: BDV-1, -2, -3, and -4

3.2.15.1. Surveillance tests

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST program. Valve stroke times for the BDIVs, based on remote (MCB) indication, are measured quarterly. Stroke time is measured by turning the hand switch to closed and measuring the time until the valve open indicating light is off and the closed indicating light is on. Note that the test instructions do not advise the operator to maintain the switch in the "Open" position when reopening the valve (or initially opening it for stroke time measurement). Note that the BDIVs do not have a seal-in circuit, and therefore require that the operator hold the switch to "Open" until the valve is fully open. (The reason that this is noteworthy is that the stroking procedures for other valves that have the seal-in circuit, such as FCV-1-17 and -18, do advise the operator to hold the switches during stroking).

The maximum allowable in-service test stroke times for the BDIVs follow:

BDV-1: 7.2 s
BDV-2: 10.0 s*
BDV-3: 7.4 s
BDV-4: 10.0 s*

ST-3A and -3B are tests that verify automatic operation of plant equipment in response to various simulated conditions, including SI, loss of offsite power, and Phase A containment isolation. These tests are performed on an 18-month frequency, during Mode 5 (cold shutdown). The BDIVs are verified to close during the Phase A isolation signal portion of the test. The test does not specifically call for the BDIVs to be reopened following the Phase A sequence. Subsequent test sequences, such as the SI sequence, result in the generation of a closure signal to the BDIVs (because the AFW pumps start on an SI signal and because an SI signal causes a Phase A isolation signal). However, closure is not verified in the test, and, in fact, it is probable that the BDIVs would not be reopened after the Phase A isolation test.

3.2.15.2 Frequency of test operation

The BDIVs are stroked according to the following procedures:

Procedure	Number of full strokes[a]	Frequency
ST-3A and -3B	2	Refueling
ST-7	1	Refueling
ST-8	1	Quarterly
ST-9	1	Quarterly
ST-10 and -13	1	Quarterly
ST-15	1	Hot standby (≤quarterly)[b]
ST-25	1	Monthly
ST-27	1	Refueling

[a] Stroking of the valves is only called for in ST-10 and -13 and ST-3A and -3B; however, valve stroking should occur automatically in the other procedures because the AFW pumps are started. Note that there are other tests conducted during refueling shutdowns that cause AFW pumps to start, and thus cause closure signals to be sent to the BDIVs; however, since SG blowdown would normally be secured during this time, there is no stroking assumed.

[b] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: The above test frequency information would yield about 29 full strokes per year; however, the BDIVs would also be stroked open and closed during plant startup and shutdown.

*Based on Technical Specification limitations.

3.2.15.3 Relevant operating instructions

OP-2 is the SG blowdown operating procedure. It specifies a maximum blowdown flow rate of 75 gal/min per SG. Per OP-2, the BDIVs are closed whenever blowdown is secured. However, the procedure specifically instructs that the BDIVs are not to be used to secure blowdown, rather that they are to be closed after blowdown is secured (flow is isolated by a common downstream regulating valve). The procedure also specifies that the BDIVs not be used to place blowdown in service. Blowdown is placed in service by initially opening one SG BDIV (and inside isolation valve) to pressurize the piping upstream of the common line isolation valve, then opening the BDIVs from the other SGs, and finally opening the common regulating valve. (One of the intents of this sequence is to minimize water hammer associated with either securing blowdown or placing it in service.)

GOP-1, which is the general operating instruction for taking the plant from cold shutdown to hot standby, specifies that blowdown is to be placed into service when the RCS is ~200°F.

GOP-3, which is the general operating instruction for taking the plant from minimum load to cold shutdown, specifies that blowdown is to be secured when the RCS is <200°F.

The emergency procedures, which are based on generic Westinghouse guidelines, frequently associate the SG blowdown valves with AFW. For example, in EOP-0 ("Reactor Trip or SI Emergency Procedure"), the procedural instructions that "Verify AFW Status" include the following conditions for verification:

AFW pumps – RUNNING
AFW LCVs in AUTO
If SG level < 33%, then verify AFW flow
SG blowdown valves – CLOSED

3.2.15.4 Comments

The BDIVs are not verified to close in response to start of the AFW pumps. There is not a specific Tech Spec requirement that requires BDIV closure in response to an AFW pump start. However, failure of the BDIVs to close would substantially diminish the effective flow delivery capability of the AFW pumps. The impact that blowdown has on AFW is implicitly confirmed by the inclusion of blowdown isolation verification under the heading of "AFW Status" in the emergency procedures. The impact of unisolated blowdown can, in part, be gathered from the 1985 water hammer event at San Onofre (See NUREG-1190[1]).

The fact that verification of blowdown isolation is included in the emergency procedures under "AFW Status," which is checked at an early point in the procedures, provides some assurance that the valves will be closed following a transient-induced reactor trip (whether as a direct result of the AFW pumps starting or as a result of operator action).

The stroke testing of the BDIVs, which is done as a part of the ASME Section XI program, strokes the valves manually and does so by use of the ganged switch that controls not only the BDIV but the inside containment isolation valve as well. The flow conditions under which the BDIVs are stroked are not specified. The ability of the BDIVs to close and the speed with which they would close depends, in part, on the extant flow and pressure conditions. The worst case conditions under which the valves would have to close would be at high pressure and flow, and without the assistance provided by the simultaneous closure of the inside containment isolation valves. (These valves only close on a Phase A isolation, which in turn, only occurs automatically as the result of an SI. Note that design-basis demand conditions for the BDIVs, and the AFW system, correspond to heat-up conditions that would not necessarily cause an SI.) The testing that demonstrates operability of the BDIVs causes both the BDIVs and the inside containment isolation valves to close and is performed under nominal pressure/flow conditions.

3.2.16 AFW Turbine Steam Supply Valves: MOV-11 and -12

3.2.16.1 Surveillance and maintenance tests/inspections

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST program. Valve stroke times for MOV-11 and -12, based on remote (MCB) indication, are measured quarterly. MOV-11 is stroke time tested from open to closed by turning the valve hand switch to the CLOSE position and holding the switch in CLOSE until the valve open indicating light is off and the closed indicating light is on. MOV-12 testing is similar, except that it is stroke-timed from closed to open. It is noteworthy that by keeping the valve hand switches in the CLOSE or OPEN position until valve travel is complete, the seal-in features of the valve open and close coils are not demonstrated. Valve stroke times, based on local observation of valve stem movement, are checked every 2 years and compared with stroke times recorded remotely. Local position is verified to agree with remote position indication every 2 years. The maximum allowable stroke times for the SSVs are 15.9 s for MOV-11 and 20.0 s for MOV-12.

ST-23, which is performed every 18 months, verifies that the thermal overload heaters are operating properly. The thermal overload trip time at rated full load current is demonstrated to be greater than twice the maximum allowable stroke time, and the trip time at locked rotor current is demonstrated to be between 10 and 15 s.

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators that is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting of the limit switch positions, per MI-6A; measurement of resistance from each phase to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6A is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, based either on valve travel measurement or the number of handwheel turns, are set as follows: (1) open limit switch set to open at 95 to 98% of valve travel, and (2) close limit switch set to open at 97 to 98% of valve travel.

MI-8 is used to verify the time delay relay associated with the automatic steam supply transfer times out at 60 s. The procedure does not actuate any equipment; it only verifies timing. There is no designated frequency of testing. A commitment to periodically calibrate the timers was made in a licensee event report filed by Plant A.

3.2.16.2 Frequency of test operation

The SSVs are stroked according to the following procedures:

Procedure	Number of full strokes[a]	Frequency
ST-6	1	Refueling
ST-7	1	Refueling
ST-8	1	Quarterly
ST-10 and -13	1	Quarterly
ST-15	1	Hot standby (≤quarterly)[b]
ST-25	1	Monthly
ST-27	1	Refueling
MI-2A and -2B	1	Refueling
MI-3A and -3B	1	Refueling

[a] Stroking of the valves is only called for in ST-10 and -13 and MI-2A and -B; however, valve stroking should occur automatically in the other procedures because the T&T valve will open, but the turbine will not roll.
[b] It is assumed that this test is performed twice per year.

Total estimated test-related full strokes per year: 25

3.2.16.3 Relevant operating instructions

OP-1 is the AFW operating procedure. In the valve checklist portion of the procedure, the "Required Position" for MOV-11 and -12 is listed as "Operable," with a footnote that states: "If steam supply is aligned from S/G A, MOV-11 will be open and MOV-12 will be closed. If steam supply is aligned from S/G D, MOV-12 will be open and MOV-11 will be closed."

The procedure does not provide direction for the steam supply transfer sequence. The knowledge that both steam supply valves cannot be open simultaneously may be considered "skill of the craft"; however, it would appear prudent to either include provision for accomplishing the transfer in the procedure or a precaution noting the existence of the interlock.

3.2.16.4 Comments

The normal AFW operating procedure (OP-1) allows for a normal standby condition where SG D is the steam supply source to the AFW turbine. If the plant were operated in this condition, it would be susceptible to credible accident conditions outside of the analyzed bounds.* An example is a feedline break in SG D with a single failure of loss of "A" train ac (or loss of dc, which would also cause loss of ac) power. This would result in only the "B" AFW pump being available for service, and with only one intact SG (SG C) serviced by the "B" pump. The loss of ac power would prevent the "A" pump from operating and would also prevent remote switchover from SG D to SG A as the steam supply for the TDP (steam supply valves are powered from the "A" train).

*This problem was independently identified by utility personnel after the completion of ORNL's review of procedures. OP-1 now specifies that an LCO must be entered if the AFW system alignment is configured with SG D as the available steam supply source for the turbine.

There is no testing that demonstrates the automatic steam supply transfer function. As a result, there are three relays and numerous contacts associated with the automatic transfer function that are not verified to operate properly. The apparent basis for not testing the automatic transfer is that it is assumed that operator action switches over to the alternate supply source. However, there are no specific steps in any normal, abnormal, or emergency procedure to so direct. It could possibly be argued that this is "skill of the craft" knowledge. In light of the fact that the interlock preventing both valves from being open simultaneously is not mentioned in any operating procedure, as well as the fact that the automatic transfer is not even mentioned in the FSAR, this appears to be a somewhat debatable proposition.

Although not used to demonstrate operability of MOV-11 and -12, ST-15 demonstrates that each steam supply line provides sufficient steam to the turbine to allow the TDP to deliver $\geq$220 gal/min to each SG (the test is run to prove full-open stroking of check valves C-28 and C-29). Note that the procedure includes the following directives relative to transferring the turbine steam supply source from SG A to SG D:

1. Manually close T&T using HS-T&T located on M-3.
2. Close MOV-11 and verify MOV-12 automatically opens.

The closure of the T&T valve will most likely prevent the automatic transfer from occurring (depending on the relationship of discharge pressure and T&T valve position – if the T&T valve bc contacts close before discharge pressure drops below 100 psia, the automatic transfer will not occur; alternatively, if discharge pressure drops below 100 psia before the T&T valve bc contacts close, then the automatic transfer should occur). Note that the Plant A FSAR does not discuss the automatic steam supply transfer design. The FSAR does take credit for operator action, in a general sense, in that auxiliary feedwater is assumed to be initiated 10 min after the trip with the feed rate of 440 gal/min. The specific operator actions that are required are not identified.

As a general comment on the design configuration, it is noted that this is not a normal arrangement for AFW turbine steam supply systems. At most plants, either both valves would be normally open, and the T&T valve shut, or the T&T valve would be open and both steam supply valves shut. In the latter case, the normal design would call for *both* steam supply valves to open on an automatic start signal. There are advantages to each design. The Plant A design provides protection against blowing down two SGs in the event of a secondary system pipe or valve failure by ensuring that both AFW turbine steam supply valves are not open simultaneously. Other designs depend solely on the check valves that are in series with the isolation valves to provide automatic protection against the possibility of blowing down two SGs. On the other hand, the Plant A design effectively lacks redundancy of steam supply sources, since the ability to open MOV-12 depends on MOV-11 being closed.

3.2.17 AFW Turbine Steam Supply Isolation Valves: MOV-9 and -10

3.2.17.1 Surveillance and maintenance tests/inspections

ST-10, -11, and -13 are surveillance procedures that implement valve stroke time and remote position indication requirements of the ASME Section XI Pump and Valve IST program. Valve stroke times for MOV-9 and -10, based on remote (MCB) indication, are measured each time the plant is put in cold shutdown. The valves are stroke time tested from open to closed by turning the valve hand switch to the CLOSE position and holding the switch in CLOSE until the valve open indicating light is off and the closed indicating light is on. Note that by keeping the valve hand switches in the CLOSE position until valve travel is complete, the seal-in features of the valve close coils are not demonstrated. Valve stroke times, based on local observation of valve stem movement, are checked every 2 years and compared with stroke times recorded remotely. Local position is verified to agree with remote position indication every 2 years. The maximum allowable stroke time for the SSIVs is 10 s (based on design criteria).

ST-23, which is performed every 18 months, verifies that the thermal overload heaters are operating properly. The thermal overload trip time at rated full load current is demonstrated to be greater than twice the maximum allowable stroke time, and the trip time at locked rotor current is demonstrated to be between 10 and 15 s.

MI-9 is the procedure by which the temperature switches are calibrated. Each switch is calibrated once per refueling cycle. The calibration only verifies proper setpoints for the switches (automatic valve closure is not verified).

MI-4 is a procedure that provides instructions on the testing of motor-operated valves using the MOVATS system, which is used to assess the general mechanical and electrical control conditions of the valves.

MI-5 is a preventive maintenance procedure for LIMITORQUE actuators and is used to maintain equipment qualification. It provides for inspection and cleaning of electrical components; cleaning, inspection, and relubrication of the geared limit switch train; inspection and replacement (if needed) of gaskets; setting of the limit switch positions, per MI-6A; measurement of resistance from each phase to ground from the supply breaker; inspection and replacement (if needed) of the operator lubricant; cleaning and relubrication of the valve stem; lubrication of the sleeve top bearing (if a grease fitting is provided); inspection of the shaft seal for excessive leakage; and inspection of the spring pack for hardened grease.

MI-6A is a corrective maintenance procedure that is used periodically (as invoked by MI-5) to adjust motor-operated valve limit and torque switch settings. Limit switch settings, which can be set based either on valve travel measurement or the number of handwheel turns, are set as follows:

1. Open limit switch: Set to allow valve to open to within 98 to 99% of full travel (the open limit switch is initially set at ~90% of full travel, then the valve is stroked electrically and valve travel measured, and the open limit switch setting is modified as necessary to achieve the 98 to 99% travel).
2. Close limit switch: Set to allow valve to close to within 99 to 100% of full travel (but with the limit switch set to open at no greater than 98% of full travel).

3.2.17.2. Frequency of test-related operation

The SSIVs are stroked according to the following procedures:

Procedure	Number of full strokes	Frequency
ST-3A and -3B	2	Refueling
ST-6	1	Refueling
ST-7	1[a]	Refueling
ST-8	1	Quarterly
ST-10 and -13	1	Cold shutdown[b]
ST-10 and -13 for T&T valve	1[c]	Quarterly
ST-14	1	Quarterly
ST-25	1	Monthly

[a] Only one of the two valves is designated to be stroked.
[b] It is assumed that this test is performed twice per year.
[c] Only MOV-9 is designated to be stroked.

Total estimated test-related full strokes per year: The above test frequency information would yield about 25 full strokes per year for MOV-10 and 29 full strokes per year for MOV-9; however, these valves are likely to be stroked more frequently, since they would be probable candidates to isolate steam from the AFW turbine for clearance purposes.

3.2.17.3 Relevant operating instructions

OP-1 and -6 (both procedures specify valve and breaker positions).

3.2.17.4 Comments

The automatic isolation feature associated with these valves is not demonstrated.

Although not used to demonstrate operability of MOV-9 and -10, ST-15 demonstrates that the steam supply line provides sufficient steam to the turbine to allow the TDP to deliver $\geq$220 gal/min to each SG.

3.3 FAILURE MODES AND FEATURES THAT ARE NOT DETECTABLE BY CURRENT MONITORING PRACTICES

The review of the cooperating utility's design and the current operation, maintenance, and surveillance procedures provided the basis for an assessment of the detectability of potential sources of component and system degradation or failure by current programmatic monitoring practices.

An assignment of potential failure modes for each of the AFW system components was made based upon the specific design functions of the component. For each failure mode, a determination was made of the extent to which the failure would be detectable. Note that the failure modes assigned are very specific to the system function of each particular component; thus two physically identical components may have different failure modes.

Tables 3.1–3.17 summarize the designated failure modes and associated areas of failure nondetectability.

To gain at least a measure of perspective, the results of the nondetectability review for Plant A were discussed with individuals from a plant operated by another utility. This plant will be designated as the "Comparison Plant." Because of design differences between the two plants, several of the designated failure modes are not applicable at the Comparison Plant. Conversely, the Comparison Plant would have some failure modes that are not applicable at Plant A (note that a detailed list of failure modes for the Comparison Plant was not established). For those failure modes that are applicable to both, it was found that monitoring practices at the Comparison Plant would detect many of the failure conditions that are apparently not detectable at Plant A. Two notable areas of nondetectability that are common to both plants relate to (1) the ability of the AFW pumps to function properly when either operating simultaneously or when using the alternate source of water and (2) the ability of the turbine-driven pump to satisfactorily perform under low steam supply pressure conditions.

Table 3.1. Pump suction check valves (SCV): C-4 (motor-driven pump A), C-3 (motor-driven pump B), and C-5 (turbine-driven pump)

Failure mode	Nondetectability
1. The SCV fails closed, preventing flow from the CST reaching the pump suction.	None. Failure to open would be observed during any of the TDP or MDP starts.
2. The SCV fails to open sufficiently to allow required flow to the pump suction.	(a) This should be observed, to an extent, during the full flow testing of the AFW pumps. It should be noted, however, that degradation could occur without observation, since neither pump flow nor differential pressure, which would be rough indicators of the general flow path conditions, are not monitored. Rather, the only parameters monitored are flows to the SGs, and even that is not quantified, except that flow to each SG is >220 gpm. (b) The MDP SCVs are not included in the periodic disassembly and inspection program (ST-28), even though they would be more subject to wear than the TDP SCV (which is included in ST-28). In this context, it should also be noted that failure of an MDP SCV to open sufficiently to allow required flow would result in a degraded suction pressure condition at the pump that would not be detected by the suction pressure switches, which are located upstream of the SCVs for the MDPs.
3. The SCV fails to close when the ESW suction valves open to provide flow to the pump suction.	Failure to close would be noted during the quarterly testing, which demonstrates closure. However, gradual degradation of the MDP SCVs might not be noticed, since they are not included in the periodic disassembly and inspection program (ST-28).

Table 3.2. Emergency service water (ESW) to motor-driven pumps supply valves MOV-1, -2, -3, and -4

Failure mode	Nondetectability
1. Valve operator fails to open in response to a low-pressure condition at the pump suction.	(a) It appears that only one of three possible logic coincidences is verified to result in an open signal. Also, not all conditions that cause low suction pressure (such as improperly positioned or broken manual valves and stuck-closed suction check valves) are detectable by the existing design. It is doubtful that operator intervention would be rapid enough to avoid pump cavitation and/or binding, and the potential associated damage, given the existence of only a single annunciator and no other control room indication. (b) As noted in the discussion for the SCVs (Sect. 3.3.1), a low-pressure condition could exist at an MDP suction without being detected by the suction pressure switches if, for example, the SCV failed to open sufficiently or if the manual suction isolation valve were improperly positioned. (c) The upstream valves (MOV-1 and -3) are not restroked after reconnecting the control circuit leads following testing of MOV-2 and -4 in ST-6, thereby creating the potential for improper reconnection going undetected until the next test.
2. With the ESW valves opened, insufficient flow is available.	There is no test that verifies flow, which would be a direct indication of adequate valve opening, as well as an indication that the piping is sufficiently clear to allow the required flow (which is of some concern because the ESW water is lake water, and the piping is therefore subject to general corrosion, Asiatic Clam buildup, and the collection of other foreign material). The valve stroking that is done under the ASME Section XI program does check stroke time from closed to open quarterly and verifies that remote position indication is consistent with local position indication every 2 years.
3. The opening sequence and associated response time result in pump damage and/or turbine overspeed tripping.	Because a switchover to ESW is never actually tested (with good reason), the ability of the switchover to occur smoothly is not demonstrated. While this is probably more a design concern than an aging concern, it would appear to be a substantial system challenge to complete the transfer under the most severe, credible circumstances (seismic event) without at least temporary pump loss.

Table 3.3. Emergency service water to turbine-driven pump suction isolation valves: MOV-5, -6, -7, and -8

Failure mode	Nondetectability
1. Valve operator fails to open in response to a low-pressure condition at the pump suction.	None noted.
2. With the ESW valves opened, insufficient flow is available.	There is no test that verifies flow, which would be a direct indication of adequate valve opening, as well as an indication that the piping is sufficiently clear to allow the required flow (which is of some concern because the ESW water is lake water, and the piping is therefore subject to Asiatic clam buildup or the collection of other foreign material). The valve stroking that is done under the ASME Section XI program does check stroke time from closed to open quarterly and verifies that remote position indication is consistent with local position indication every 2 years.
3. MOV-7 and -8 fail to close in response to an automatic close signal.	Automatic closure of these valves is not included as an acceptance criterion in any test. ST-7 does include a note that the valves will close after opening; however, it is not an acceptance criterion.
4. The opening sequence and response time result in pump damage and/or turbine overspeed tripping.	Because a switchover to ESW is never actually tested (with good reason), the ability of the switchover to occur smoothly is not demonstrated. While this is probably more a design concern than an aging concern, it would appear to be a substantial system challenge to complete the transfer under the most severe, credible circumstances (seismic event) without at least temporary pump loss.

Table 3.4. Motor-driven AFW pumps

Failure mode	Nondetectability
1. Pump fails to start upon demand.	None noted.
2. Pump fails to continue to run after starting.	The ability of the pumps to continue to operate satisfactorily during and following transfer of the suction source to ESW is not demonstrated by surveillance testing.
3. Pump fails to load shed upon demand.	None noted.
4. Pump fails to deliver required flow to the SGs.	There is apparently no testing that verifies that an MDP can deliver the required flow to its two SGs at the required pressure conditions. ST-15 does verify that each MDP can deliver >440 gal/min total flow to two SGs, but does not monitor actual flow, SG pressure, or developed pump head. Also, there is no testing that verifies proper operation of the AFW pumps when *all* the pumps are operating simultaneously. It should also be noted that operating procedure guidance appears to require that the operators leave the MDPs running on recirculation flow when not batching the SGs. This practice would result in accumulated pump wear due to the low flow operation that would not necessarily be detected by the ST-15 testing because only flow is monitored.
5. Pump auxiliary contacts fail to provide required control inputs to other automatically actuated equipment.	Auxiliary contacts used to provide control signals to the MDP level control valves, the alternate suction source valves, and SG blowdown valves are apparently not verified to function properly.

Table 3.5. Turbine-driven AFW pump

Failure mode	Nondetectability
1. T&T valve operator fails to open in response to an automatic AFW turbine start signal. (Turbine fails to start on demand.)	(a) The thermal overload switch bypassing, which is designed to occur on all safety related starts, does not appear to be verified. (b) The thermal overload settings are apparently not verified. (c) It is not clear that the station blackout signal-generated start of the TDP is verified. The extent of testing is to verify that the T&T valve will open when contacts from one undesignated train are jumpered (as opposed to closing automatically).
2. T&T valve operator fails to complete the close-open strokes in response to the automatic steam supply transfer signal (fails to close or fails to reopen).	(a) The circuit that enables the automatic transfer of steam supply sources does not appear to be tested at all. (b) See items a and b under Failure mode 1 above.
3. Valve electronic overspeed trip function fails to trip the valve before the mechanical overspeed trip occurs, thereby requiring local resetting (and preventing automatic restart).	(a) The electronic overspeed trip is tested under simulated, rather than actual operating conditions. (b) There is no apparent verification of the automatic operation of the T&T valve closing coil to drive the motor to shut, thereby relatching the motor to the valve, following an electronic overspeed trip . (c) The mechanical overspeed trip setpoint is apparently not verified under simulated or actual conditions.
4. Pump fails to develop required flow	(a) Full flow developed during ST-15. However, pump condition is not fully monitored (procedure verifies flow to each SG to be >220 gpm, but does not monitor other pump parameters). (b) There is no testing performed to verify the ability of the TDP to deliver required flow at steam supply pressures <842 psig. In fact, Tech Specs require testing to be performed with steam pressure $\geq$842 psig.
5. Valve stem-operated switches fail to provide input signals to other AFW related equipment or functions.	There is apparently no verification of proper operation of the following switches: (a) The switch that results in automatic closure of SG blowdown isolation valves and provides the permissive to allow the automatic steam supply transfer to occur. (b) The switch that causes the T&T valve operator to drive the operator to the shut position following an electronic overspeed trip. (c) The switch that starts the TDP room ventilation fan.

Table 3.6. Pump miniflow check valves: C-6, -8, and -10

Failure mode	Nondetectability
1. The miniflow check valve (MCV) fails closed, or fails to open sufficiently to allow required recirculation flow.	The quarterly pump testing, using ultrasonic flow instrumentation, provides an indication that the MCV is stroking open adequately to allow the designated minimum flow. However, the flow rate is so low that the valves would not be fully stroked. Also, it is questionable whether the flow rates are adequate to provide pump protection.

Table 3.7. Common miniflow check valves: C-1 and -2

Failure mode	Nondetectability
1. A common miniflow check valve (CMCV) fails closed or fails to open sufficiently to allow required recirculation flow.	The performance testing does not demonstrate that each check valve allows at least a given amount of flow to pass, rather that several pumps can operate simultaneously. Verification that the valves open sufficiently to prevent pump overheating can only be demonstrated by monitoring flow. Note that if flow were monitored in ST-16, some assurance of proper valve functioning would be provided; however, in light of the low flow conditions normally experienced by these valves, it would appear that periodic disassembly and inspection or other monitoring would also be appropriate.

Table 3.8. Pump discharge check valves: C-7, -9, and -11

Failure mode	Nondetectability
1. The discharge check valve (DCV) fails closed or fails to open sufficiently to allow adequate flow to reach the SGs.	In all probability, this would be observed during the ST-15 testing. However, as noted previously, only flow is monitored during the testing. Thus, a DCV could open sufficiently to allow the required flow at test conditions, but limit flow to less than required under different pressure conditions.
2. The DCV fails to close to prevent reverse flow.	There is apparently no testing that demonstrates that the DCV keeps reverse flow below some acceptable value. However, reverse flow protection offered by the combination of valves in the discharge flow path is verified during normal operation (by observation of pump casing and discharge piping temperature).

Table 3.9. Motor-driven AFW pump level control valves: LCV-1/1A, -3/3A, -5/5A, and -7/7A

Failure mode	Nondetectability
1. The MDP level control valve (MDLCV) controller fails to automatically control SG level in response to an MDP start signal.	(a) The deenergization of the AFW blackout relays is not demonstrated to result in the energization of relays that must function properly to enable various actions in the MDLCV control circuits, including transfer of the controllers from manual to automatic. This is not judged to be a significant concern since the valve switches are normally maintained in AUTO. (b) The transfer from MDLCV to BMDLCV control, including the accompanying closure of the MDLCVs, is apparently not verified by testing. This is primarily a concern from the standpoint of minimizing flow to a faulted SG until the flow can be isolated altogether by manual actions. (Note that the ability to transfer from automatic control to manual control in the presence of an accident signal is not demonstrated, per item 5 below.) Failure of this transfer to occur should be noted, however, when the MDPs are used to maintain SG inventory during plant shutdown and startup conditions.
2. Valve operator does not open or stay open in response to a demand from the controller.	The deenergization of the MDLCV solenoids (that allows the valves to open/modulate automatically) following an automatic pump start does not appear to be demonstrated. All testing is performed with the valve switches in MANUAL (which itself deenergizes the valve solenoid).
3. Valve fails to open sufficiently to allow adequate flow.	In all probability, this would be observed during the ST-15 testing. However, as noted previously, only flow is monitored during the testing. Thus, an MDLCV could open sufficiently to allow the required flow at test conditions, but limit flow to less than required under different pressure conditions.
4. Valves fail to close sufficiently to prevent excessive flow to a faulted SG or to prevent feedwater backleakage.	There is apparently no testing that is specifically oriented toward detecting seat leakage. Reverse flow protection offered by the combination of check valves plus the level control valves is observable during normal operation. It is possible that excessive MDLCV or BMDLCV seat leakage might be observed during startup and shutdown evolutions, or possibly during routine pump testing (in recirculation).
5. Valve cannot be placed in manual control following an AFW actuation signal.	The ability to transfer the control of the MDLCVs from automatic to manual in the presence of an AFW actuation signal does not appear to be demonstrated. Inability to transfer to manual control would prevent the operators from isolating flow to a faulted SG except by additional operator intervention or by stopping the associated pump. The inability to transfer to manual control could also aggravate recovery efforts in the event that there was an automatic controller failure.

Table 3.10. Turbine-driven pump level control valves: LCV-2, -4, -6, and -8

Failure mode	Nondetectability
1. Valve controller fails to automatically open/close to control SG level in response to a TDP start signal.	None noted.
2. Valve operator does not open or stay open in response to a demand from the controller.	(a) The ability of the accumulator to stroke the valve and the proper seating of the control air check valve for the accumulator are apparently not demonstrated. (b) The deenergization of the valve solenoids, which allows the turbine-driven pump level control valves (TDLCVs) to open/modulate, is not demonstrated with the control switches in AUTO. The solenoids are also deenergized by placing the control switches in MANUAL, and all test-related deenergization of the solenoids is demonstrated with the control switches in MANUAL.
3. Valve operator does not drive the valve closed to prevent excessive flow to a faulted SG.	There is apparently no testing that demonstrates that the valves are driven shut in response to a faulted SG condition. In addition, the ability to transfer from AUTO back to MANUAL in the presence of an accident signal does not appear to be demonstrated (this ability allows the operator to deal with a faulted SG remotely).
4. Valve does not close sufficiently to prevent excessive flow to a faulted SG or to prevent feedwater backleakage.	There is apparently no testing that is specifically oriented toward detecting seat leakage. Reverse flow protection offered by the combination of check valves plus the level control valves is observable during normal operation. Excessive TDLCV seat leakage might be observed during startup and shutdown evolutions, or possibly during routine pump testing (in recirculation).
5. Valve fails to open sufficiently to allow adequate flow.	In all probability, this would be observed during the ST-15 testing. However, as noted previously, only flow is monitored during the testing. Thus, a TDLCV could open sufficiently to allow the required flow at test conditions, but limit flow to less than required under different pressure conditions.
6. Valve cannot be placed in manual control following an AFW actuation signal.	The ability to transfer the control of the TDLCVs from automatic to manual in the presence of an AFW actuation signal does not appear to be demonstrated. Inability to transfer to manual control would prevent operators from remotely isolating flow to a faulted SG except by stopping the TDP. The inability to transfer to manual control could also aggravate recovery efforts in the event of automatic controller failure.

Table 3.11. Level control valve check valves: C-12 through -19

Failure mode	Nondetectability
1. The level control valve check valve (LCVCV) fails closed or fails to open sufficiently to allow adequate flow to reach the SGs.	In all probability, this would be observed during the ST-15 testing. However, as noted previously, only flow is monitored during the testing. Thus, a LCVCV could open sufficiently to allow the required flow at test conditions, but limit flow to less than required under different pressure conditions.
2. The LCVCV fails to close to prevent reverse flow.	There is no testing that demonstrates that the LCVCV keeps reverse flow below some acceptable value. Reverse flow protection offered by the combination of check valves plus the level control valves is observable during normal operation.

Table 3.12. Steam generator B and C AFW to main feed check valves: C-21, -22, -24, and -25

Failure mode	Nondetectability
1. The main feed check valve (MFCV) fails closed or fails to open sufficiently to allow adequate flow to reach the SGs.	Degradation of these valves should be observed during the periodic inspection performed per ST-28. Also, in all probability, this would be observed during the ST-15 testing. However, as noted previously, only flow is monitored during the testing. Thus, an MFCV could open sufficiently to allow the required flow at test conditions, but limit flow to less than required under different pressure conditions.

Table 3.13. Main feedwater check valves (FWCV): C-20, -23, -26, and -27

Failure mode	Nondetectability
1. The main feedwater check valve (FWCV) fails to close sufficiently to ensure that adequate AFW flow is delivered to the SG.	The periodic disassembly and inspection of these valves provides reasonable assurance that the valve internals are in proper operating condition. The leak rate testing, however, allows for leakage substantially in excess of the level required to meet AFW system design requirements.

Table 3.14. Feedwater isolation valves: FWIV-1 through -4

Failure mode	Nondetectability
1. The feedwater isolation valve (FWIV) fails to close in response to an automatic or manual closure demand signal.	None noted. Because manual closure is depended on, from an AFW system perspective, manual closure performed in conjunction with valve in-service testing adequately simulates the control aspect of closure.
2. FWIV fails to close sufficiently to prevent excessive backleakage from the SG and/or AFW.	There is apparently no testing that checks for FWIV seat leakage. Because the upstream feedwater control valves and the downstream check valves provide some redundancy, and the FWIVs are gate valves, this is not viewed as a significant concern.

Table 3.15. Steam generator blowdown isolation valves (BDIVs): BDV-1 through -4

Failure mode	Nondetectability
1. The SG blowdown isolation valves (BDIVs) fail to close in response to an automatic closure signal associated with start of an AFW pump.	There does not appear to be any testing that verifies that the BDIVs close in response to any AFW pump start. The start indication of the TDP comes from a T&T valve stem-mounted limit switch, which also provides a start indication for the automatic steam supply transfer. Operation of these limit switch contacts does not appear to be checked. The start indications of the MDPs come from 52S/b contacts. These contacts are apparently not verified to operate properly. The BDIVs <u>are</u> verified to close in response to a containment Phase A isolation signal, as well as in response to the control board switch. The only electrical circuit features not verified by this testing are the relay and contact operations associated with pump starts. It should be noted that the test conditions are substantially different from design basis demand conditions, in that the flow rate is relatively low, and an upstream valve is simultaneously closing to isolate flow.
2. The BDIVs fail to close sufficiently to isolate blowdown flow.	There is apparently no testing that checks the extent to which blowdown flow is isolated by the BDIVs. Note that blowdown is normally secured using downstream, nonsafety-related valves.

Table 3.16. AFW turbine steam supply valves: MOV-11 and -12

Failure mode	Nondetectability
1. The automatic transfer sensing circuit fails to initiate an automatic steam supply transfer.	Other than verifying the setpoint of the TDP discharge pressure switch, apparently none of the automatic transfer circuit (including various relays and contacts) is tested.
2. MOV-11 fails to close on demand (from either the automatic transfer circuit or from the main control board switch).	Energization of the close coil by the automatic transfer logic does not appear to be verified by testing. However, the ability to close the valve using the control switch is demonstrated periodically.
3. MOV-12 fails to open on demand (from either the automatic transfer circuit or from the main control board switch).	Energization of the open coil by the automatic transfer logic is apparently not verified by testing. However, the ability to open the valve using the control switch is demonstrated by various periodic testing.
4. MOV-11 motor operator contacts fail to provide proper permissive to MOV-12.	The ability of MOV-12 to be opened (and stay open) in various tests demonstrates that the MOV-11 ac contacts (which are open when MOV-11 is shut) are not causing automatic closure of the valve. There is apparently no testing, however, that demonstrates that closure of the MOV-11 ac contacts causes MOV-12 to close. The MOV-11 bc contact (closed when the valve is shut) portion of the automatic open circuit also does not appear to be demonstrated by any testing, since all transfers are made manually.
5. MOV-12 motor operator contacts fail to provide steam supply transfer permissive.	This is apparently not demonstrated because there is no testing that verifies the automatic transfer sequence.
6. Steam supply valves (SSVs) fail to open sufficiently to allow required steam flow.	The ability of each SSV to provide the required steam flow is reasonably well demonstrated in ST-15. However, because steam flow is partially dictated by pump power demands, and only pump flow (not differential pressure) is monitored, the steam flow demanded during testing may be somewhat less than that required during a demand event. Also, there is no testing at low steam supply pressures. It should also be noted that the periodic stroking of the SSVs is performed by holding the switches in the CLOSE/OPEN positions until the stroke is completed, thus not demonstrating that the seal-in portion of the MOV-12 opening circuit is functioning.

Table 3.17. AFW turbine steam supply isolation valves: MOV-9 and -10

Failure mode	Nondetectability
1. A steam supply isolation valve (SSIV) closes during a TDP demand condition without a pipe break existing.	There appears to be no testing that requires an extended run period for the TDP. Because the automatic isolation is based on ambient temperature, it is not clear that stable ambient conditions would be reached in the short time required for pump testing.
2. SSIV fails to close on demand.	There is apparently no testing to verify that automatic closure will occur. Although the temperature switches are individually calibrated, neither the automatic closure of the isolation valves nor even continuity in the automatic closure circuit is verified. It should be noted that failure to close would not constitute an AFW system failure, but could adversely impact other equipment in the vicinity.
3. SSIV fails to open sufficiently to allow the required steam flow.	The ability of the SSIVs to allow the required steam flow is reasonably well demonstrated in ST-15. However, because steam flow is partially dictated by pump power demands, and only pump flow (not differential pressure) is monitored, the steam flow demanded during testing may be somewhat less than that required during a demand event. Also, there is no testing at low steam supply pressures.
4. SSIV fails to close sufficiently to isolate a leak/break.	There is apparently no testing to verify the extent to which the SSIVs isolate steam flow. However, the SSIVs would be used to isolate steam for clearance and test purposes, and excessive leakage should be detected at that time.

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*Available for purchase from National Technical Information Service, Springfield, Virginia 22161.

+Copies are available from U. S. Government Printing Office, Washington, D. C. 20402.

4. AFW SYSTEM FAILURE DATA REVIEW AND ANALYSIS

4.1 INTRODUCTION

To gain some insight into the importance of various AFW system components from a historical failure perspective, reviews of failure data through 1986 for Westinghouse and B&W plants from INPO's Nuclear Plant Reliability Data System (NPRDS),* the Nuclear Operations Analysis Center's Licensee Event Report (LER), and S. M. Stoller's Nuclear Power Experience (NPE) data bases were conducted. The initial intent of reviewing all three data bases was to provide an indication of the validity of relying on only the NPRDS data because it should be theoretically the most comprehensive set of data; in fact, all failures that would be reported in LERs should also be reported in NPRDS, whereas NPRDS should also include many failures not reported in LERs. However, it became clear during the initial review of failure data from these data bases that a significant fraction of the failure records found in the NPE and LER data bases was not found in NPRDS. As a result, each record from all three data bases was reviewed and combined to form a single ORNL data base, thereby avoiding redundant entries while establishing a more thorough set of failure records.

It was also determined that for meaningful results to be gathered from the data review, a single, consistent assignment of several parameters for each failure record was required. This determination was based largely on the fact that the NPRDS failure records, in particular, (1) assigned the failures to incorrect types of components (e.g., a turbine speed-control problem that resulted in tripping of the TDP being designated as a pump failure instead of a turbine/governor failure), (2) attributed single failures to multiple components (e.g., when a turbine speed-control problem caused the turbine to trip, a failure record was entered for both the turbine and the TDP), and (3) inconsistently ascribed various characteristics to the failures.

A third reason for establishing the ORNL data base was to assign the failure records to a level that was meaningful, from a system perspective, because the component assignment of failure was not structured to facilitate a system review. This was especially true for instrumentation and control (I&C) components. The importance of a particular type of I&C failure, from a system perspective, depends on which other components are affected; therefore, it was necessary to assign such failures to the component(s) ultimately affected. An example of such a situation would be the failure of a pressure transmitter. Depending on the transmitter function, the result of the transmitter loss might range from simple loss of indication to loss of speed control for the TDP.

Although a greater degree of internal consistency was obtained by the creation of the ORNL data base than was available in the existing data bases, it is extremely important to realize that any conclusions drawn from the review of the ORNL data base must be made with great care. One feature of the failure records that is particularly noteworthy is the change in reporting requirements and practices that occurred around 1983 to 1984. During that time, the LER reporting requirements were changed, substantially reducing the number of failures reportable to the NRC in LERs. At the same time, utility NPRDS reporting practices began to improve (in part because improved voluntary failure reporting to the NPRDS was used to justify the relaxation of LER reporting requirements). As a result, the

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*Plant-specific information from the NPRDS data base is proprietary. Although much of the failure data compilation and evaluation depended on plant and component identification, the results of the study are presented without identification of individual plants.

total failure data available from NPRDS are dominated by the data from 1984 and later. Almost three-quarters of the NPRDS failure records for the AFW system come from 1984 to 1986, and about one-half of the total failure record data (from all three sources) can be found in the NPRDS data for those 3 years alone. As a result, information such as failure rate as a function of plant age for a particular plant, or even for industry as a whole, can be extremely misleading. Because of this and other complicating factors, any attempt to use the failure record data results or findings included in this report for any purpose other than ones that are specifically discussed within the report is strongly discouraged without consultation with the author.

Another aspect of the failure data base that should be pointed out is that very few, if any, of the failures are associated with design basis challenges of the AFW system. Although some failures are classified as demand related, they occurred primarily when an automatic or manual start of the AFW system occurred during testing or following a "normal" reactor trip (not, for example, following a design-basis event such as a feedwater line break). Recognize that the challenges presented to various components may be more severe under design-basis conditions; therefore, certain types of failure are more likely. Thus, it would be inappropriate to directly extrapolate the failure data associated with the normal AFW system and general plant conditions to those that would exist following design-basis events.

A limitation of the failure data that must be discussed relates to the completeness of the data. Although a significant number of failure records are in the ORNL failure data base (1767 total), it clearly does not include a large fraction of known historical failures, based on a review of some plant-specific failure data that were available for comparison. However, the three sources of data used to form the ORNL data base are reasonably accessible and usable, in contrast to plant-specific data (available only from maintenance work requests that normally contain considerably less information than is available from the NPRDS, LER, or NPE data bases).

A final observation about the failure data is that even plants that are very thorough in their reporting practices can only report failures when they are known to exist. As discussed in Chap. 3, a number of failure types would not be identifiable by current monitoring practices. For example, the disk for a check valve may have separated and be lying in the bottom of the valve body. If there are no reverse flow closure challenges to the valve, either from testing or from operational circumstances, the failure may go undetected and, hence, unreported for a considerable time. Thus, even full reporting of known failure data would not necessarily be a perfect representation of the distribution of areas of concern.

4.2 ORNL DATA BASE FORMATION

Computerized searches of the NPE, LER, and NPRDS data bases were conducted. Because the failure data available from the NPRDS included failure records from Westinghouse and B&W plants through most of 1986, the NPE and LER data base search records for the same time periods were included. The initial review process consisted of sorting each of the data bases by plant, failure date, and component. At this time, the ORNL component assignments were made. The three sources of data were then combined to form a single data base, which was then processed to eliminate multiple entries for the same failure event. The single set of failure records was then reviewed again to evaluate and record the method of discovery, the impact on the AFW system, and other pertinent information.

For each component type, the numbers of failure counts in the data base and the effect upon the system as a whole were tallied. Some explanation of the component categorization and other aspects and limitations of the data presented are necessary:

1. Five component types are designated. The failures ascribed to particular component types include not only failures of the component proper, but failures of auxiliary components or parts that affected the component. For example, the failure of a contact in the AFW turbine control circuitry that resulted in overspeed tripping of the TDP would be included under the pump driver category. Table 4.1 provides descriptions of the component types and their scope. The more important component types were divided into subgroups for further evaluation. The subgroups will be discussed later.
2. Three parameters are provided for most sortings of the failure data base: failure counts (FCs) – the number of failure records associated with the described parameter; average system effect (ASE) – the average fraction of the system degraded per failure; and relative system degradation (RSD) – a measure of the overall historical system degradation associated with the described parameter.
3. The ASE was determined for each failure record based on the particular plant design and the extent to which the system was affected by the component failure. The effect was measured on a scale from 0 to 1, with 1 representing total system failure and 0 representing no, or insignificant, impact on the system. For example, if one MDP in a three-pump system would not start because of a faulty circuit breaker, a system effect of 0.33 would be assigned for that failure (note that this failure would be included in the pump driver category).
4. The RSD is a normalized measure of the overall contribution of a component type to total system degradation, taking into account both the number of failures and the significance of each event. The method used to determine the RSD is as follows:

$$RSD = FC_i \times ASE_i / \Sigma(FC_i \times ASE_i) \ ,$$

where

RSD = RSD for a component type,
ASE = ASE for a component type,
FC = FCs for a component type,
i = individual failure record.

This method of assigning the RSD allows the different sources of AFW system degradation to be compared on an equivalent basis. Where the RSD is used in this report, keep in mind that the values cited are in the context of the level of review. To illustrate, pump drivers were found to be responsible for 37% of the RSD for the AFW system as a whole (see Table 4.2). Of the three types of pump drivers, the turbine drive was found to be responsible for 73% of the RSD associated with pump drivers. Thus, failures associated with turbine drives were responsible for $0.73 \times 0.37 = 0.27$, or 27% of the overall AFW RSD.
5. The ASE and RSD measures cited above do not include an accounting for recoverability, that is, the ability to recover the failed piece of equipment within a short time. This is primarily caused by the difficulty in ascertaining the extent to which operator action would be able to offset many failures experienced. Thus, two failures of the same component may be given identical consequence ratings when, in fact, one of the failures could be overcome fairly easily.
6. Each failure record in the data base is predicated on information from one or more of the information sources (NPE, LER, and NPRDS). Each "failure" record is not necessarily a failure that disables the component. For instance, the valve "failure" records range from packing leaks to broken valve stems. The system effect for these two failure types would clearly differ, but each would contribute one failure count. It is

Table 4.1. Component categorization

Component type	Scope of equipment
Pump drivers	Components included in the pump driver scope are (1) the pump driver itself, whether turbine, diesel, or motor, including mechanical and electrical parts of the driver; (2) the control circuitry for the driver, including breakers, contacts, relays, etc., that are required to operate properly to start and/or control the pump driver; and (3) auxiliary components whose function is integral with the pump driver; for example, the turbine GV is included because it is used to control turbine speed.
Valve operators	Includes the valve operator itself (e.g., the motor), any portion of the operator controls, including switches, contacts, controllers, etc. Does not include failures of the valve or valve stem. Valve operators for AFW pump suction, discharge, and turbine SSVs are included.
Valves	This category includes failures of all types of valves, including check, gate, globe, butterfly, etc. Note that the turbine governor and T&T valves are specifically not included. External leakage, seat leakage, and stem failures are examples of failures included.
Pumps	Pumps only, regardless of drive type, are addressed by this category. Bearing failures, pump lube oil problems, air or vapor binding of the pumps, pump suction problems, and pump overpressurization problems are included.
Other	Includes all components not addressed by the above categories, including pipes, pipe supports, and noncontrol instrumentation (i.e., instruments used for indication only).

Table 4.2. Component failure record summary

Component type	FCs	ASE	RSD
Pump drivers	402	0.36	0.37
Valve operators	534	0.20	0.28
Valves	418	0.16	0.18
Pumps	144	0.33	0.12
Other	269	0.06	0.04
Total	1767	0.22	1.00

important, therefore, to realize that the failure count information can be particularly misleading in terms of relative significance.

A total of 517 reactor years of operating experience for the plants is included in the ORNL failure record data base. The plants included were Westinghouse and B&W units that started in or before 1986. These plants have 130 safety-related AFW pumps, including 77 motor-driven, 51 turbine-driven, and 2 diesel-driven pumps. The accumulated pump operating experience for the time period covered by the data base was 808 MDP train-years, 604 TDP train-years, and 13 DDP train-years.

4.3 ANALYSIS RESULTS

4.3.1 General Summary

A total of 1767 FCs, many of which were reported in more than one of the three data base sources, were reviewed. As shown in Fig. 4.1 and Table 4.2, valve operator (including air, motor, electrohydraulic, and solenoid valve operators) problems resulted in the largest number of FCs, contributing 30% of the total (534/1767). Valves and pump drivers provided 24% and 23% of the total FCs, respectively.

The ASE of failures associated with pump drivers and pumps was found to be 0.36 and 0.33, respectively. In contrast, the average effects associated with the valve operator and valve categories were 0.20 and 0.16, respectively. The ASE of a pump or pump driver failure is greater than a valve or valve operator failure because a single failure of a pump or pump driver causes the loss of an entire train, whereas a valve or valve operator failure normally results in only partial loss of a train.

As noted previously, failure count comparisons alone can be misleading. To gain a better perspective on the overall degradation associated with failures of particular components, the RSD for each was determined. Even though there were fewer associated FCs for pump drivers than for valve operators or valves, pump drivers were found to be the leading contributor to AFW RSD, accounting for about 37% of the total, while valve operators and valve failures accounted for 28% and 18%, respectively. Pump failures

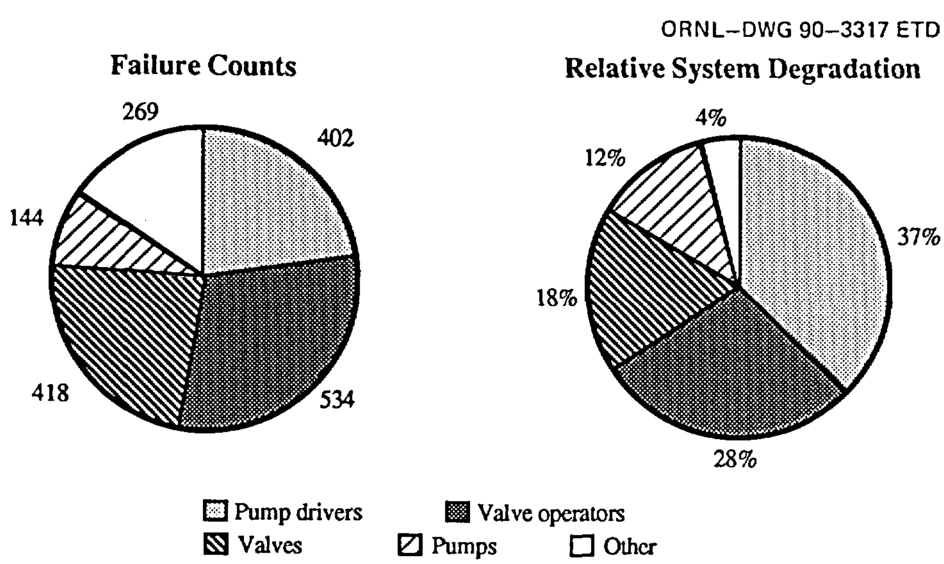

Fig. 4.1. Failure count and relative system degradation distributions.

contributed ~12% of the historical RSD. The reason that both the pump driver and pump categories were found to cause a higher fraction of RSD than the associated fraction of FCs would suggest is that, as noted above, the ASE of a pump or pump driver failure was substantially greater than that for a failure of a valve or valve operator.

4.3.2 Method of Detection Summary

The method of discovery of each failure record was designated during the review process. The FCs, ASE, and RSD associated with the component types by the method of detection are reported in Tables 4.3 to 4.5 and summarized in Fig. 4.2. Three methods of detection were ascribed as follows:

1. Those failures found by programmatic monitoring methods, such as Technical Specification Surveillance testing. This would include failures detected during testing, even if the component that was found to be failed was not specifically being checked by the test.
2. Those failures found during routine equipment observation, such as by noting valve stem leakage or by unusual indication or alarm at the main control board.
3. Those failures that were only found during an operational demand, such as failure of a pump to automatically start following a reactor trip with a legitimate start signal present.

Note that the total FCs included in the three categories are slightly less than the total FCs identified in Table 4.2 (and in some other tables) because some failure detection means were either not clear or did not fit any of the categories.

Overall, 230 of the 1767 (13%) FCs and 18% of the RSD were due to failures detected during demand events. Several features of Fig. 4.2 and Tables 4.3 to 4.5 are particularly noteworthy:

1. Over one-fourth of the pump driver FCs and pump driver-related RSD were associated with on-demand failure.
2. The failures detected during demand were, in general, more severe than those detected otherwise. As an example, the ASE of all demand failures was 0.30 compared with

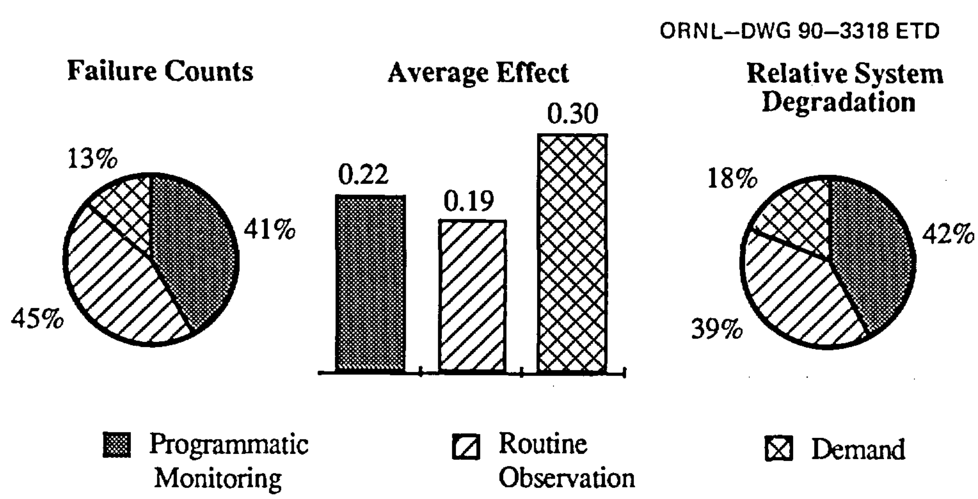

Fig. 4.2. Method of detection summary.

Table 4.3. FCs, by discovery method

Component type	Programmatic monitoring	Routine observation	Demand	Total
Pump drivers	180	126	95	402
Valve operators	236	223	73	534
Valves	124	269	23	418
Pumps	47	71	26	144
Other	144	108	13	269
Total	731	797	230	1767

Table 4.4. ASE, by discovery method

Component type	Programmatic monitoring	Routine observation	Demand	Total
Pump drivers	0.35	0.33	0.39	0.36
Valve operators	0.20	0.20	0.20	0.20
Valves	0.20	0.14	0.27	0.16
Pumps	0.37	0.30	0.33	0.33
Other	0.06	0.04	0.18	0.06
Total	0.22	0.19	0.30	0.22

Table 4.5. RSD, by discovery method

Component type	Programmatic monitoring	Routine observation	Demand	Total
Pump drivers	0.17	0.11	0.10	0.37
Valve operators	0.12	0.12	0.04	0.28
Valves	0.06	0.10	0.02	0.18
Pumps	0.05	0.06	0.02	0.12
Other	0.02	0.01	0.01	0.04
Total	0.42	0.39	0.18	1.00

0.22 and 0.19 for all failures detected by programmatic monitoring and routine observation, respectively.
3. Over one-half of the RSD associated with demand failures was due to pump driver failures.

4.3.3 Subsystem Review Summary

One of the designators applied to each failure record was the subsystem affected. Four types of subsystems were designated. Three subsystems are related to the type of pump driver (i.e., TDP, MDP, and DDP). For failures associated with components common to two or more trains with different types of pump drivers, the subsystem was designated as "common." An example of a common subsystem component would be a flow control or isolation valve located downstream of the junction of TDP and MDP discharge lines. When the affected subsystem was indeterminate, "unknown" was assigned.

Figure 4.3 and Tables 4.6 to 4.8 provide failure data sorted by affected subsystem. Failures within the TDP subsystem were found to have contributed almost half of the total FCs and over half (58%) of the RSD. MDP subsystem failures were found to account for about 30% of the FCs and RSD. The significance of the TDP subsystem failure records is amplified by the fact that there are more MDPs than TDPs (77 MDP subsystems vs 51 TDP subsystems, with 808 and 604 pump-years cumulative service, respectively, for the units and operating periods included in the ORNL data base).

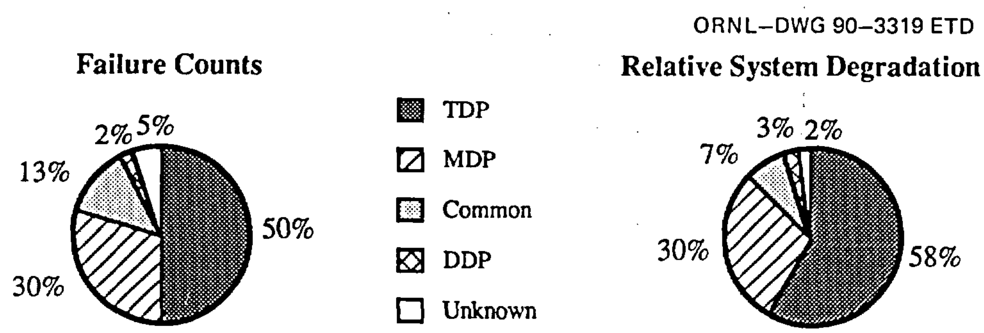

Fig. 4.3. Failure by subsystem summary.

4.3.4 Plant Age Review Summary

Failure records were sorted by the age of the plant at the time of component failure and then divided into 5-year age groups. Because of the diversity of plant ages, normalization of the data was necessary to account for the fact that there have been more reactor years of operation in the lower age groups. The results of the the age-related sorting of the data are presented in Tables 4.9 and 4.10.

Some cautions relative to this particular data sort are extremely important. First, aging trends that may appear to be extant based on Tables 4.9 and 4.10 may, in fact, not be present at all. These tables are based on failure records and reactor years of operation for the life of all plants included in the data base. However, the failure record data base, as mentioned previously, is heavily influenced by failures reported from 1984 to 1986

Table 4.6. FCs, by subsystem affected

Component type	TDP	MDP	Common	DDP	Unknown	Total
Pump drivers	290	87	0	25	0	402
Valve operators	258	209	51	2	14	534
Valves	210	129	59	1	19	418
Pumps	60	83	0	0	1	144
Other	62	30	112	2	63	269
Total	880	538	222	30	97	1767

Table 4.7. ASE, by subsystem affected

Component type	TDP	MDP	Common	DDP	Unknown	Total
Pump drivers	0.36	0.31	N/A	0.49	N/A	0.35
Valve operators	0.22	0.19	0.20	0.25	0.19	0.20
Valves	0.16	0.17	0.17	0.25	0.10	0.16
Pumps	0.34	0.32	N/A	N/A	0.50	0.33
Other	0.09	0.03	0.05	0.00	0.07	0.06
Total	0.25	0.21	0.11	0.43	0.10	0.22

Table 4.8. RSD, by subsystem affected

Component type	TDP	MDP	Common	DDP	Unknown	Total
Pump drivers	0.27	0.07	0.00	0.03	0.00	0.37
Valve operators	0.15	0.10	0.03	0.00	0.01	0.28
Valves	0.09	0.06	0.03	0.00	0.01	0.18
Pumps	0.05	0.07	0.00	0.00	0.00	0.12
Other	0.01	0.00	0.01	0.00	0.01	0.04
Total	0.58	0.30	0.07	0.03	0.02	1.00

Table 4.9. FCs per reactor year, by 5-year groups

Component type	Years 1-5	Years 6-10	Years 11-15	Years 16-20	Years 1-20
Pump drivers	0.75	0.78	0.84	0.95	0.79
Valve operators	1.06	0.95	1.17	1.00	1.04
Valves	0.66	0.87	1.07	0.77	0.82
Pumps	0.27	0.23	0.44	0.09	0.28
Other	0.48	0.58	0.46	0.68	0.52
Total	3.21	3.42	3.98	3.50	3.44

Table 4.10. RSD, by 5-year groups
(normalized for numbers of reactor years operation)

Component type	Years 1-5	Years 6-10	Years 11-15	Years 16-20	Years 1-20
Pump drivers	0.09	0.09	0.08	0.12	0.37
Valve operators	0.07	0.06	0.08	0.08	0.28
Valves	0.04	0.04	0.06	0.04	0.18
Pumps	0.03	0.03	0.05	0.01	0.12
Other	0.01	0.01	0.01	0.02	0.04
Total	0.23	0.23	0.28	0.27	1.00

because of improvements in reporting practices (particularly the case for NPRDS) during this time period. For those plants that have operated for some time, therefore, a built-in bias toward more apparent failures with age exists. Second, the age of the component whose failure is recorded may or may not be the same as the age of the plant. For example, a particular valve's operator may have been replaced or substantially refurbished several times before the occurrence of a failure that is recorded in the data base. Third, reporting practices vary considerably from plant to plant. The reporting practices of older plants, in particular, can have a substantial impact on the results of sorting of this nature. As a result, the aging relationship tables (Tables 4.9 and 4.10) should be viewed as informational data with a great deal of uncertainty.

4.3.5 Component Group Review Summary

A more detailed review and characterization of failure records for the components that were found to be major contributors to AFW RSD were performed. The component categories reviewed in more detail were pump drivers (specifically, turbines and motors), valve operators, valves, and pumps.

4.3.5.1 Pump drivers

Figure 4.4 and Table 4.11 provide a summary of pump driver failure record information from the ORNL data base. Turbines accumulated the largest number (290) of FCs of any individual component type, and over one-fourth of overall RSD was due to turbine-related failures. Almost three-fourths of both the FCs and the RSD for pump drivers was associated with turbine drives. The recorded failure count rate for the turbine drives was more than four times that of the motor drives. Although there are only two DDPs (out of the total of 130 pumps in the data base), failures associated with the diesels contributed 9% of the pump driver RSD. This is due, in part, to the fact that the ASE at plants with the DDPs is high (each unit using DDPs has only two AFW pumps; therefore, a failure of one pump causes a 50% degradation in the system). However, it also appears, based on the fairly small experience base for the DDPs (13 DDP-years) that the diesel driver failure rate may be higher than for the other type drivers.

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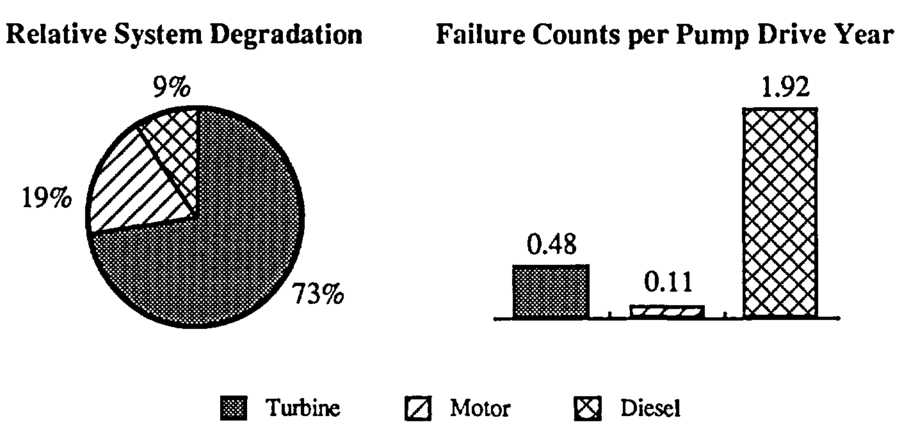

Fig. 4.4. Pump driver summary.

Table 4.11. Pump driver type summary data

Pump driver type	FCs	FCs per pump-year	ASE	RSD
Turbine	290	0.48	0.36	0.73
Motor	87	0.11	0.31	0.19
Diesel	25	1.92	0.49	0.09
Total	402	0.28	0.36	1.00

Turbines

A more detailed review and assignment of the failure sources was undertaken for the pump drivers. Figure 4.5 and Tables 4.12 to 4.1.4 present analysis results for the turbine drives, sorted by subcomponent groupings and method of discovery. The six subcomponents or failure sources designated for the turbine drives and the associated scope were as follows:

1. I&C / Governor Control
   This includes the external control circuitry that would provide start signals to the TDP (does not include failures of instrumentation used to provide input to safeguards logic circuitry, such as SG-level instrumentation), as well as the governor speed control circuit.
2. T&T Valve
   Failures of the T&T valve, such as tripping caused by worn linkage, or failure to open because of a damaged operator were included in this category. Note that T&T valve and valve operator failures are included here, and not in the valve or valve operator component groups because the T&T valve is typically a part of the turbine package and is integral with turbine starting and operation.
3. GV
   Failures of the GV, such as the valve plug sticking and external leakage, are included in this category.
4. Oil/Bearing
   Turbine bearing failures and miscellaneous bearing oil related problems are included.
5. Turbine
   Failures of the turbine itself, such as blade failure, are included.
6. Other/Unknown
   This category includes all other miscellaneous failures and those whose source could not be determined.

Problems associated with I&C/governor control circuits were the dominant source of turbine degradation, comprising about one-half the total turbine-related FCs and RSD. T&T valve problems were responsible for about one-fifth of the RSD.

One particularly noteworthy finding was that almost one-third of the I&C/governor control failures were detected during demand (see Fig. 4.6). The I&C/governor control failures were responsible for ~70% of the total turbine-related demand failures.

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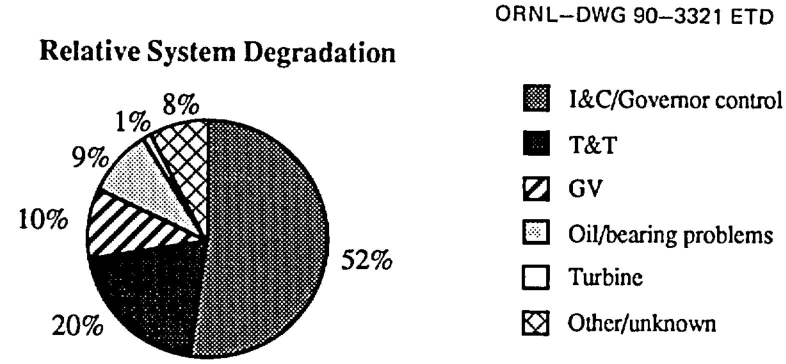

Fig. 4.5. Sources of turbine drive failures.

Table 4.12. Turbine FCs by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C/Governor control	82	24	43	149
T&T	23	29	11	64
GV	15	13	2	30
Oil/bearing	9	10	2	21
Turbine	1	4	0	5
Other/unknown	11	7	3	21
Total	141	87	61	290

Table 4.13. Turbine ASE by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C/Governor control	0.36	0.34	0.40	0.37
T&T	0.32	0.32	0.38	0.33
GV	0.37	0.29	0.42	0.34
Oil/bearing	0.46	0.39	0.42	0.42
Turbine	0.17	0.23	N/A	0.22
Other/unknown	0.41	0.33	0.33	0.37
Total	0.36	0.33	0.39	0.36

Table 4.14. Turbine RSD by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C/Governor control	0.28	0.08	0.17	0.53
T&T	0.07	0.09	0.04	0.20
GV	0.05	0.04	0.01	0.10
Oil/bearing	0.04	0.04	0.01	0.09
Turbine	0.00	0.01	0.00	0.01
Other/unknown	0.04	0.02	0.01	0.08
Total	0.49	0.27	0.23	1.00

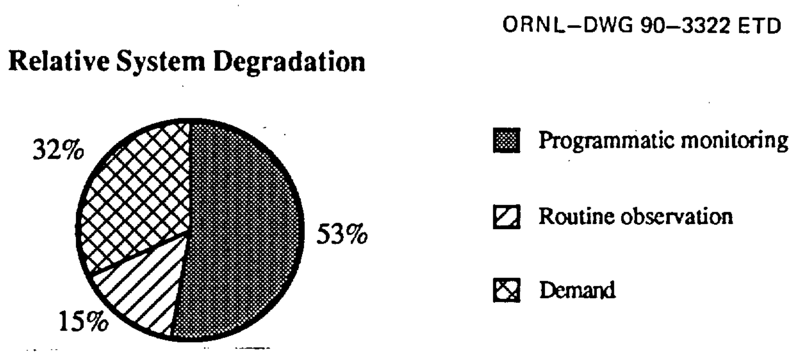

Fig. 4.6. Turbine I&C/governor failure summary by detection method.

Motors

Figure 4.7 and Tables 4.15 to 4.17 provide information for motor drives. Four pump motor subcomponent failure sources were designated:

1. I&C
   These failures include the controls that are used for automatic and manual starting of MDPs (does not include failures of instrumentation used to provide input to safeguards logic circuitry, such as SG-level instrumentation).
2. Breaker
   These failures include the breaker itself and breaker auxiliaries.
3. Motor
   These failures include all motor parts, except for the motor bearings.
4. Motor bearings
   This category is self-explanatory.

As was the case for the turbine drives, I&C-related problems were the principal source of motor-drive degradation, contributing over 50% of the total motor-drive FCs and RSD. About one-third of the I&C problems for motor drives were detected during demand conditions. The I&C failures were responsible for ~80% of the total motor-drive-related demand failures.

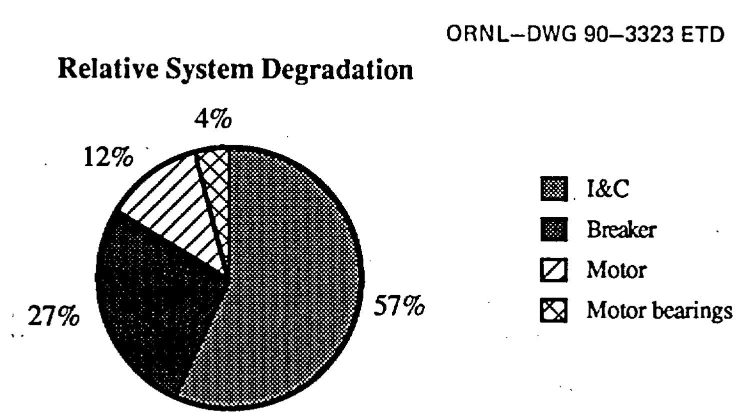

Fig. 4.7. Sources of pump motor drive failures.

Table 4.15. Pump motor FCs by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	21	14	17	52
Breaker	10	8	4	22
Motor	4	6	0	10
Motor bearings	0	3	0	3
Total	35	31	21	87

Table 4.16. Pump motor ASE by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.29	0.26	0.30	0.29
Breaker	0.31	0.37	0.29	0.33
Motor	0.33	0.33	N/A	0.33
Motor bearings	N/A	0.33	N/A	0.33
Total	0.30	0.31	0.30	0.30

Table 4.17. Pump motor RSD by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.23	0.14	0.19	0.57
Breaker	0.12	0.11	0.04	0.27
Motor	0.05	0.07	0.00	0.12
Motor bearings	0.00	0.04	0.00	0.04
Total	0.40	0.36	0.24	1.00

Diesels

Tables 4.18 to 4.20 provide failure data base information for diesel drives. Three diesel subcomponent failure sources were designated:

1. I&C
   This includes the external control circuitry that would provide start signals to the DDP (does not include failures of instrumentation used to provide input to safeguards logic circuitry, such as SG-level instrumentation), as well as the diesel governor speed control circuit.
2. Mechanical/Support
   This includes the diesel itself and noncontrol diesel supporting auxiliaries, such as fuel oil piping.
3. Other
   This is self explanatory

As was the case for the turbine and motor drivers, I&C problems were the principal source of diesel-drive degradation, with ~80% of the FCs and RSD resulting from I&C failures. One-half of the I&C failures that were recorded, comprising 40% of the total diesel failure records, occurred on demand.

4.3.5.2 Valve operators

The valve operator group, which had the highest number of FCs, 534, was found responsible for 28% of the overall RSD (see Tables 4.3 and 4.5 and Fig. 4.1). Tables 4.21 to 4.23 provide a breakdown of failure statistics of the valve operator types, including air operators (AOV), motor operators (MOV), and electrohydraulic operators (EHOV). Figure 4.8 indicates the relative proportions of system degradation attributable to the valve operator types. AOVs and MOVs were found to be roughly equal in terms of both numbers of failures and RSD. Current monitoring practices appear to be better able to detect degradation and failure of valve operators than pump drivers in that ~13% of the RSD associated with the valve operator group was found during demand conditions (Table 4.23), compared to >25% of the pump driver RSD being found during demand.

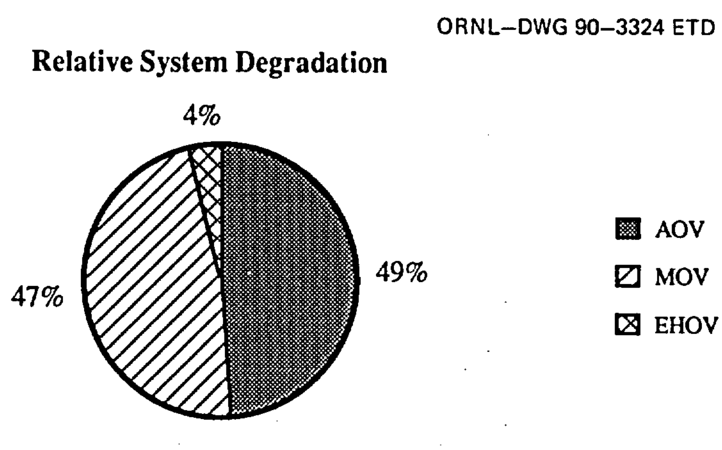

Fig. 4.8. Valve operator failure summary.

Table 4.18. Diesel subcomponent FCs by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	4	6	10	20
Mechanical/support	0	2	1	3
Other	0	0	2	2
Total	4	8	13	25

Table 4.19. Diesel subcomponent ASE by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.50	0.50	0.50	0.50
Mechanical/support	N/A	0.38	0.50	0.42
Other	N/A	N/A	0.50	0.50
Total	0.50	0.47	0.50	0.49

Table 4.20. Diesel subcomponent RSD by detection method

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.16	0.24	0.41	0.82
Mechanical/support	0.00	0.06	0.04	0.10
Other	0.00	0.00	0.08	0.08
Total	0.16	0.31	0.53	1.00

Table 4.21. FCs, by valve operator type

Operator type	Programmatic monitoring	Routine observation	Demand	Total
AOV	124	130	34	289
MOV	109	84	36	230
EHOV	3	9	3	15
Total	236	223	73	534

Table 4.22. ASE, by valve operator type

Operator type	Programmatic monitoring	Routine observation	Demand	Total
AOV	0.17	0.19	0.18	0.18
MOV	0.23	0.21	0.21	0.22
EHOV	0.33	0.31	0.28	0.31
Total	0.20	0.20	0.20	0.20

Table 4.23. RSD, by valve operator type

Operator type	Programmatic monitoring	Routine observation	Demand	Total
AOV	0.20	0.23	0.06	0.49
MOV	0.23	0.17	0.07	0.47
EHOV	0.01	0.03	0.01	0.04
Total	0.44	0.42	0.13	1.00

Air-operated valve operators

Tables 4.24 to 4.26 provide more detailed information concerning the types of failure sources for AOVs. Figure 4.9 summarizes the results. Five subcomponents or failure sources were designated:

1. I&C
   This includes the valve controller circuit, as well as items such as relays and contacts that are external to the controller circuit but that provide signals to the valve controller circuit.
2. Mechanical
   This applies to the valve operator itself, including positioner, limit switches, diaphragm, connections, and linkage.
3. Instrument Air
   This includes failures in which either instrument air supply components, such as pressure regulators, were involved or where poor instrument air quality was clearly the cause of failure. Note that some other failures, such as some solenoid failures (below) may have resulted from poor quality air, but they were not ascribed to instrument air unless the failure record description so stated.
4. Solenoids
   This includes failures of the solenoid plunger or coil.
5. Unknown/Other
   This is self-explanatory.

Of the five failure sources for AOVs, I&C problems were the single largest contributor, both in terms of FCs (131 of 289) and AOV-related RSD. About 12% of the AOV RSD was detected during demand conditions. One-half of the demand-related AOV RSD was associated with I&C failures.

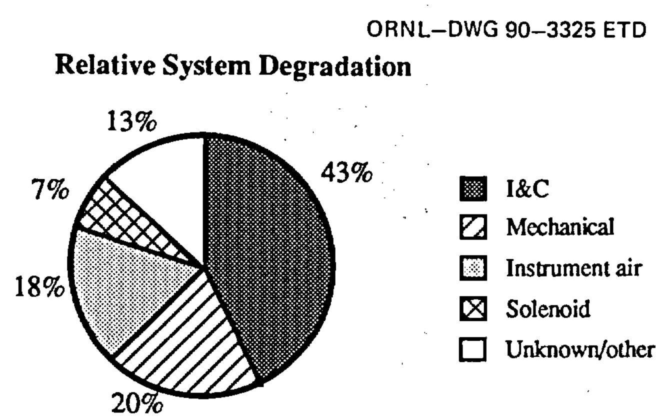

Fig. 4.9. Sources of air-operated valve operator failures.

Motor-operated valve operators

Tables 4.27 to 4.29 provide more detailed information concerning the types of failure sources for MOVs. Figure 4.10 summarizes the results. Three subcomponents or failure

Table 4.24. Air-operated valve FCs

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	55	60	16	131
Mechanical	24	27	4	56
Instrument air	26	16	5	47
Solenoid	7	12	0	19
Unknown/other	12	15	9	36
Total	124	130	34	289

Table 4.25. Air-operated valve ASE

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.16	0.18	0.19	0.17
Mechanical	0.19	0.20	0.17	0.19
Instrument air	0.19	0.22	0.20	0.20
Solenoid	0.19	0.18	N/A	0.18
Unknown/other	0.20	0.19	0.17	0.19
Total	0.17	0.19	0.18	0.18

Table 4.26. Air-operated valve RSD

Failure source	Programmatic monitoring	Routine observation	Demand	Total
I&C	0.16	0.21	0.06	0.43
Mechanical	0.09	0.10	0.01	0.20
Instrument air	0.09	0.07	0.02	0.18
Solenoid	0.03	0.04	0.00	0.07
Unknown/other	0.04	0.05	0.03	0.13
Total	0.41	0.47	0.12	1.00

Table 4.27. Motor-operated valve FCs

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Motor, switches	59	37	13	109
I&C	25	24	14	64
Unknown/other	25	23	9	57
Total	109	84	36	230

Table 4.28. Motor-operated valve ASE

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Motor, switches	0.23	0.20	0.22	0.22
I&C	0.22	0.23	0.20	0.22
Unknown/other	0.24	0.22	0.20	0.22
Total	0.23	0.21	0.21	0.22

Table 4.29. Motor-operated valve RSD

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Motor, switches	0.27	0.15	0.06	0.47
I&C	0.11	0.11	0.06	0.27
Unknown/other	0.12	0.10	0.04	0.25
Total	0.50	0.36	0.15	1.00

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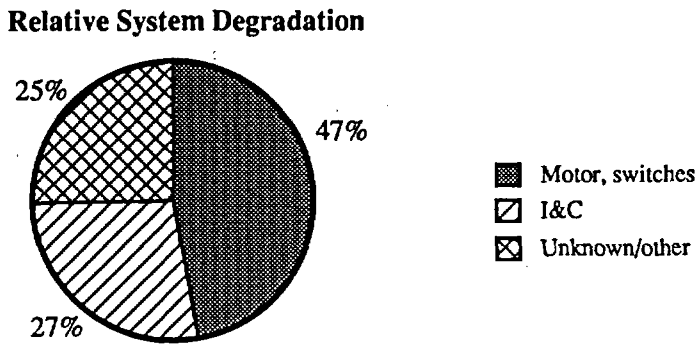

Fig. 4.10. Sources of motor-operated valve operator failures.

sources were designated:

1. Motor and Switches
   This category includes the motor operator itself and all local appurtenances, including the motor, torque and limit switches, and gearing.
2. I&C
   This category includes all remote controls, such as fuses, control relays, and contacts that operate to control power to the operator motor (primarily located at the MCC).
3. Other/Unknown
   This is self explanatory.

Failures associated with the operator motor and switches were responsible for almost half of the MOV FCs and RSD (limit and torque switch problems were the principal sources of failure within this subgroup). More than 15% of the MOV FCs and RSD was associated with demand situations.

4.3.5.3 Valves

Tables 4.30 to 4.32 provide more detailed information concerning the types of failure sources for the valve group. Valve-related failures included all valve problems that were not included in the valve operator group. No distinction was made concerning whether valves had power or manual-only operators. Failures ranged from internal (seat) and external (packing or bonnet) leakage to separation of the disk from the stem. The valve group was broken down into the following types:

1. Control valves
   This category includes all valves in either the pump suction or discharge piping, excluding check and relief valves.
2. SSVs
   This category includes all valves in the steam supply lines, excluding check and relief valves.
3. Relief valves
   This category includes all relief valves in either the steam supply or pump suction/discharge piping. This category does not include the main steam safety or atmospheric dump valves.

Table 4.30. Valve type FCs

Valve type	Programmatic monitoring	Routine observation	Demand	Total
Control valves	39	85	14	138
Steam supply valves	16	53	2	71
Relief valves	15	10	1	26
Check valves-suction/discharge	33	97	5	135
Check valves-steam supply	21	24	1	46
Total	124	269	23	416

Table 4.31. Valve type ASE

Valve type	Programmatic monitoring	Routine observation	Demand	Total
Control valves	0.17	0.14	0.27	0.16
Steam supply valves	0.22	0.11	0.25	0.14
Relief valves	0.18	0.03	0.33	0.13
Check valves-suction/discharge	0.23	0.16	0.27	0.18
Check valves-steam supply	0.18	0.14	0.33	0.16
Total	0.20	0.14	0.27	0.16

Table 4.32. Valve type RSD

Valve type	Programmatic monitoring	Routine observation	Demand	Total
Control valves	0.10	0.17	0.06	0.33
Steam supply valves	0.05	0.09	0.01	0.15
Relief valves	0.04	0.01	0.00	0.05
Check valves-suction/discharge	0.11	0.23	0.02	0.37
Check valves-steam supply	0.06	0.05	0.00	0.11
Total	0.36	0.55	0.09	1.00

4. Check valves – Suction/Discharge
   This category includes all check valves located in either the pump suction or discharge lines.
5. Check valves – Steam Supply
   This category includes all check valves between the steam supply connections to the main steam lines and the turbine.

More failures were associated with the pump suction/discharge control and check valves than SSVs, as would be expected, because of the relative populations. The only particularly notable feature from the valve group failure data is that <10% of the FCs and RSD were associated with demand failures, the smallest fraction of any of the major groups.

4.3.5.4 Pumps

Tables 4.33 to 4.35 provide more detailed information concerning the types of failure sources for the pump group. Figure 4.11 summarizes the results. Six failure/degradation sources were designated, as follows:

1. Pump Internals
   This category includes failures of any mechanical parts of the pump, with the exception of pump packing and bearings.
2. Pump Oil/Bearing
   Pump bearing failures and miscellaneous pump bearing-oil-related problems are included. Note that this does not include pump driver bearing problems.
3. Pump Overpressure
   This category includes events in which the pump casing and/or discharge piping became overpressurized.
4. Pump Packing
   This category includes failures of pump packing which resulted in either excessive leakage or in packing overheating.

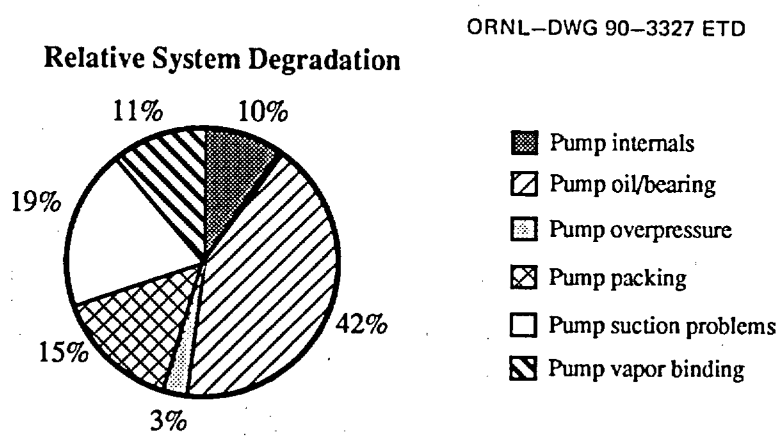

Fig. 4.11. Sources of pump failures.

Table 4.33. Pump subcomponent FCs

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Pump internals	6	3	3	12
Pump oil/bearing	23	29	2	54
Pump overpressure	1	5	0	6
Pump packing	7	21	1	29
Pump suction problems	9	1	19	29
Pump vapor binding	1	12	1	14
Total	47	71	26	144

Table 4.34. Pump subcomponent ASE

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Pump internals	0.42	0.39	0.33	0.39
Pump oil/bearing	0.39	0.35	0.42	0.37
Pump overpressure	0.33	0.17	N/A	0.20
Pump packing	0.31	0.22	0.17	0.24
Pump suction problems	0.38	0.33	0.32	0.34
Pump vapor binding	0.33	0.36	0.33	0.35
Total	0.38	0.30	0.33	0.33

Table 4.35. Pump subcomponent RSD

Failure source	Programmatic monitoring	Routine observation	Demand	Total
Pump internals	0.05	0.02	0.02	0.10
Pump oil/bearing	0.19	0.21	0.02	0.42
Pump overpressure	0.01	0.02	0.00	0.02
Pump packing	0.05	0.10	0.00	0.15
Pump suction problems	0.07	0.01	0.13	0.21
Pump vapor binding	0.01	0.09	0.01	0.10
Total	0.37	0.45	0.18	1.00

5. Pump Suction Problems
   This category covers a number of types of problems related to the pump suction, including clogged suction strainers, foreign material in the suction piping, loss of adequate suction head, and suction pressure instrumentation problems.
6. Pump Vapor Binding
   This category addresses failures in which the pump became vapor bound, usually due to backleakage from main feedwater or the SGs.

The single largest source of pump FCs (54 out of 142) and RSD (42%) was from pump bearing and oil problems. Pump suction problems were the second largest contributor (21%) to the pump-related RSD. Of the 18% of RSD associated with demand failures, 13% came from pump-suction-related problems.

4.3.6 Review by Plant

A comparative review of the reported failures from individual plants was made. This review was conducted for the purposes of identifying the significance of outliers to the general failure data trends.

Figure 4.12 provides the results of a check of the total *number* of failures reported for the plants in the ORNL data base. As noted, more than half the total reported failures came from <25% of the plants. At the other extreme, <10% of the reported failures came from over 30% of the plants.

To provide a better focus, the distribution of the historical system degradation associated with reported failures for the component types was reviewed. The results, which are provided in Fig. 4.13, are even more pronounced than the results from the check of total number of failures. More than 50% of the system degradation associated with each of the designated component groups came from <20% of the plants, while <10% of the associated degradation came from almost 50% of the plants.

At least two possible causes of these distributions exist. The first is that the reporting practices vary considerably from plant to plant. The second is that some plants have experienced more degradation or failure of certain components than others. In reality, there is some validity to both conclusions, and the results represent the combination of both causes.

Figures 4.14 and 4.15 provide perspectives on the failure reporting practices of the ORNL data base plants, based on analysis of the available failure data. From these figures, it can be seen that a consistent pattern in terms of failure reporting to NPRDS is not evident from a comparison of total FCs in the ORNL data base to FCs for which there was an NPRDS entry.

Figure 4.16 provides a comparison of the relative contributions of pump drivers, valve operators, valves, and pumps to overall system degradation at the five plants for which the greatest extent of AFW system degradation was reported. The range of percentages of total degradation for the component types among these five plants is listed below. It is evident that there is substantial diversity, in terms of the relative significance of component types to overall AFW system degradation, among the five plants.

Component	Range of RSD (%)
Pump drivers	19 to 89
Valve operators	7 to 72
Valves	1 to 35
Pumps	3 to 14

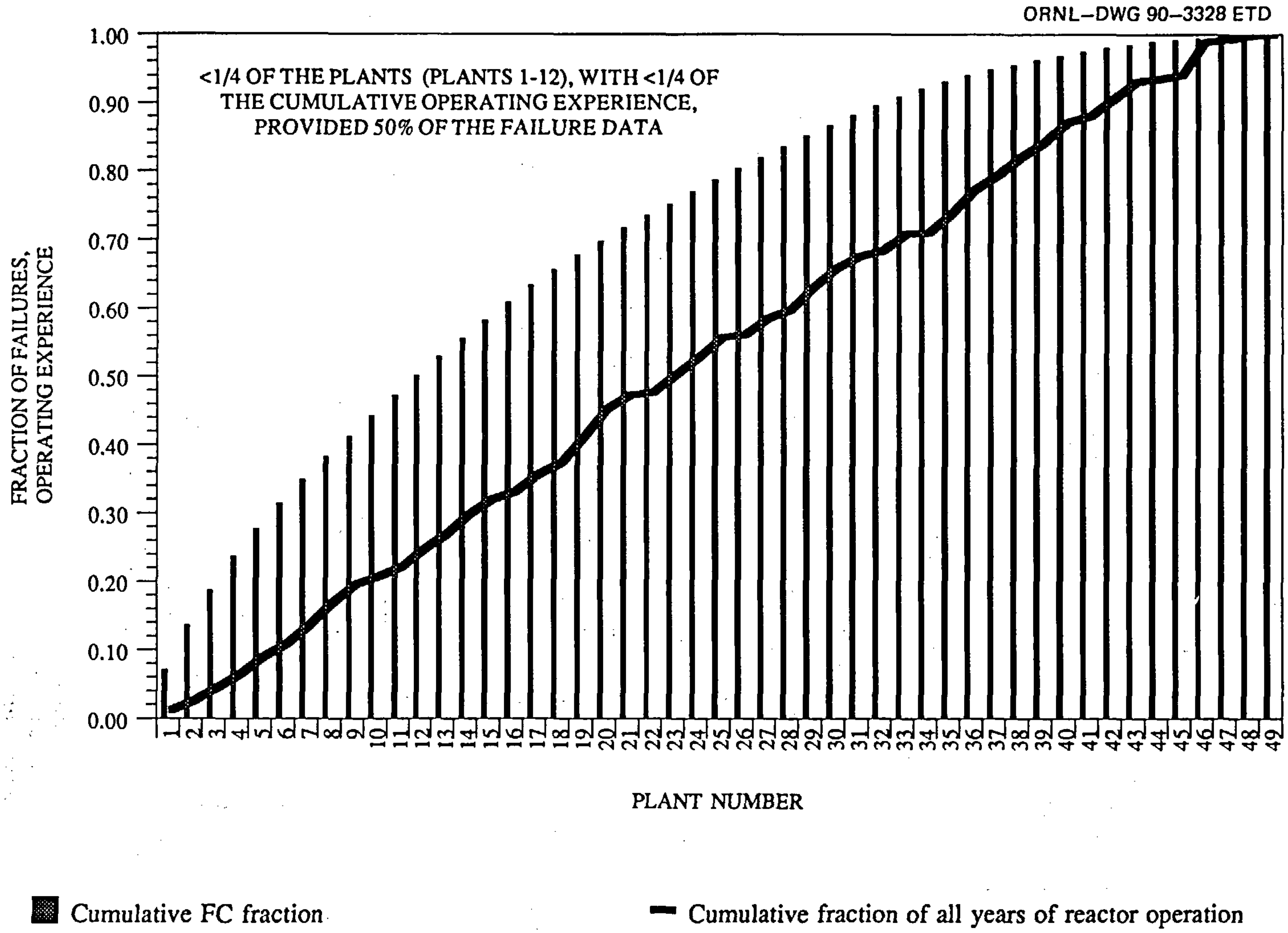

Fig. 4.12. FCs and operating experience for plants in the ORNL data base.

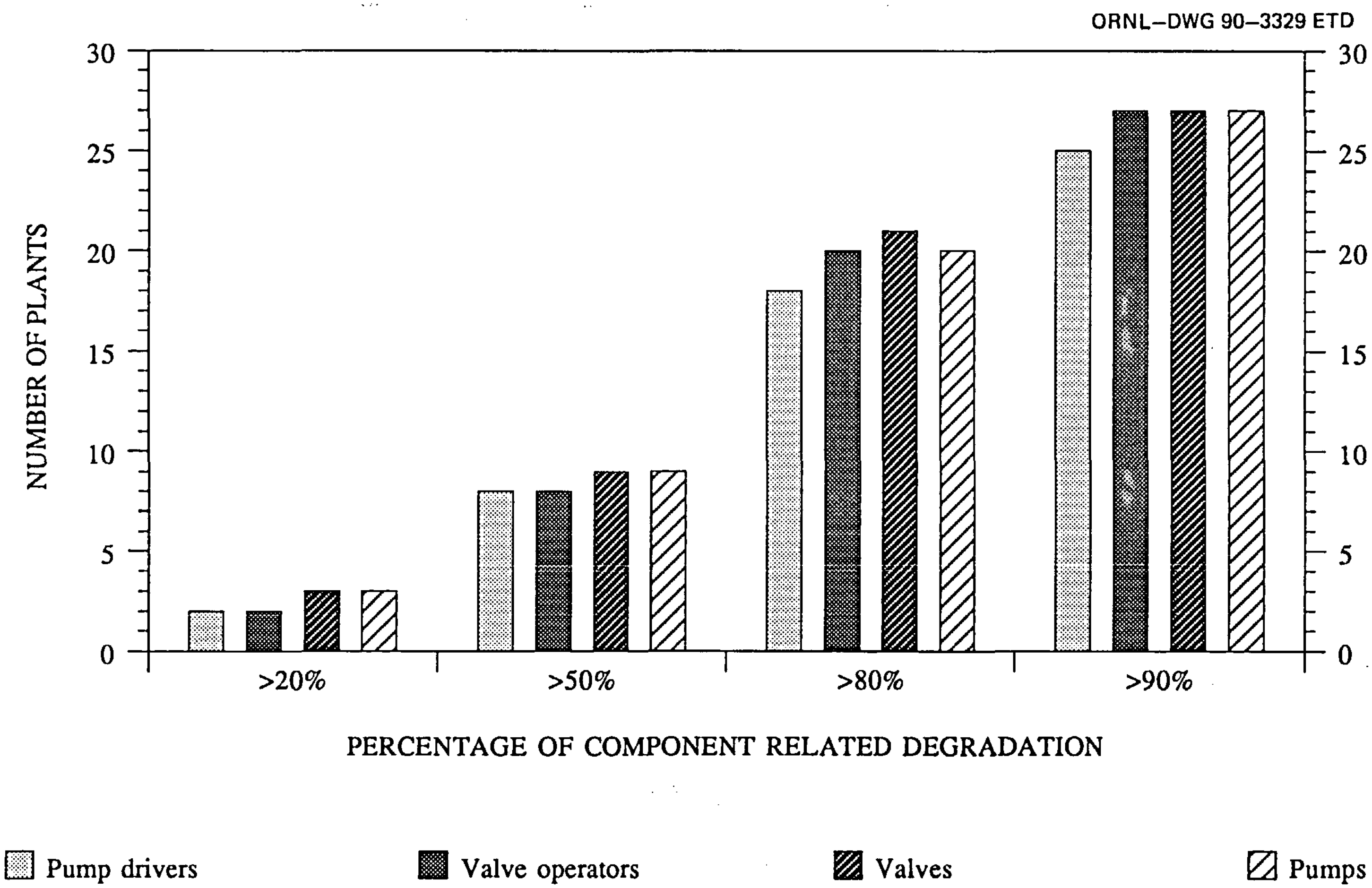

Fig. 4.13. Sources of component-related degradation.

The failures reported from 9 of the 49 plants in the data base resulted in >50% of the degradation related to each component type. Over 90% of the degradation came from just over 50% of the plants.

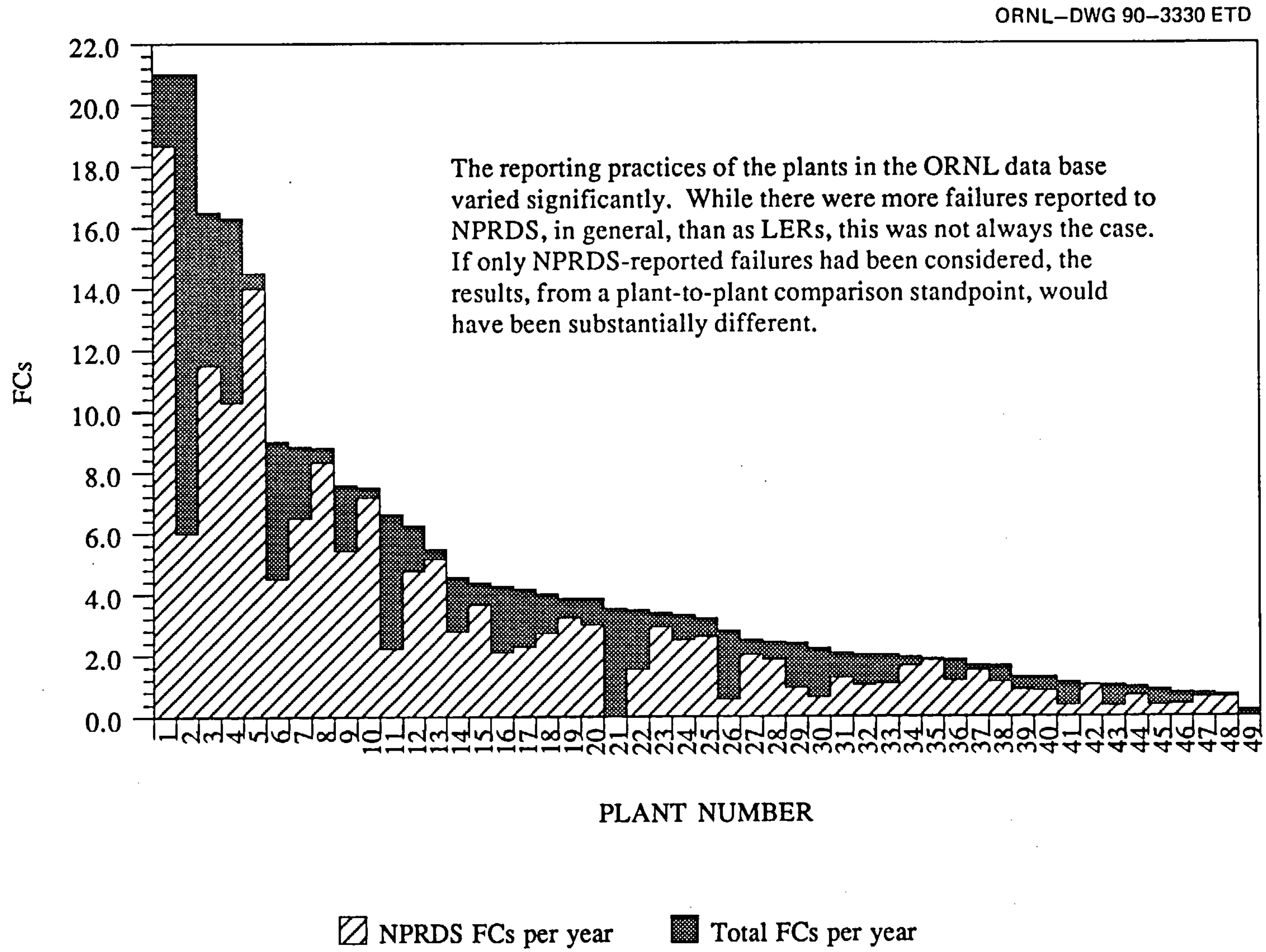

Fig. 4.14. Reported FCs per year, by source.

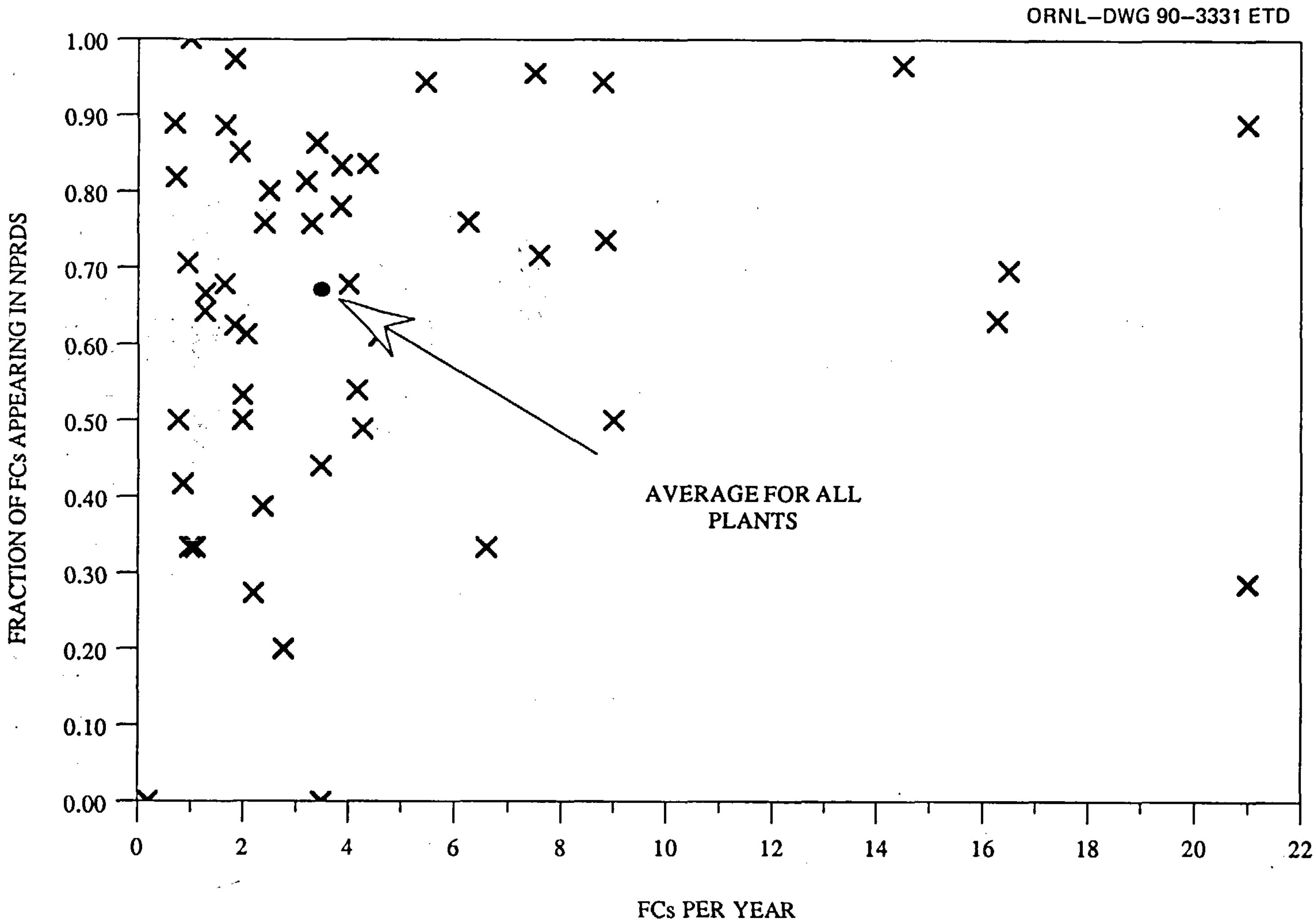

Fig. 4.15. Scatter diagram of the fraction of FCs available from NPRDS data as a function of the average number of FCs per year for all data base plants.

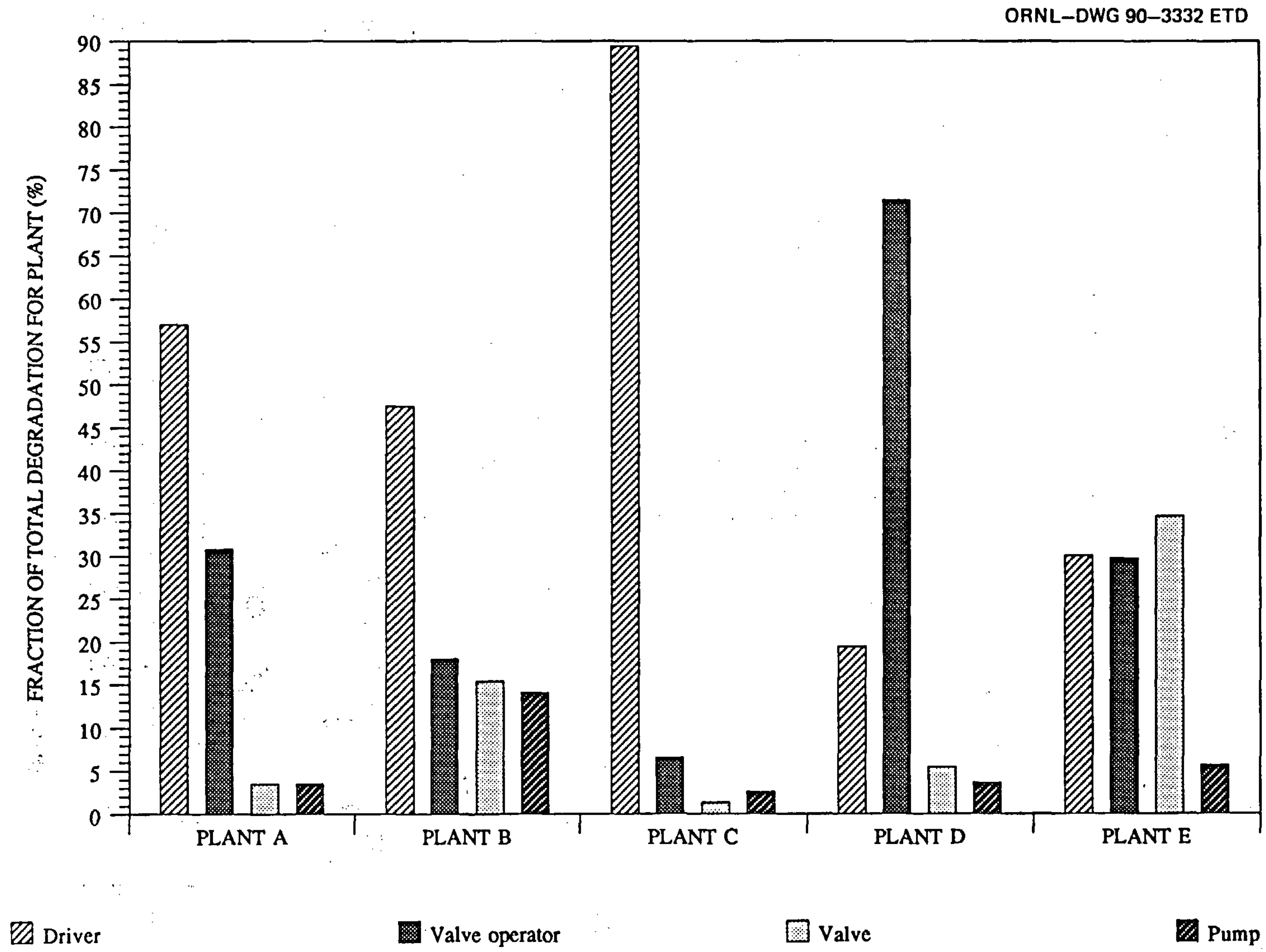

Fig. 4.16. RSD: component percentage contribution for top five plants.

5. AFW SYSTEM CONFIGURATIONS

A review of AFW system configurations was conducted for 61 B&W and Westinghouse plants that are either now operating or are scheduled for near-term operation. Only B&W and Westinghouse plants were included because the failure data used in constructing the ORNL failure data base (Chap. 4) were only available for these types of plants (note that not all 61 plants are included in the failure data base). Of the plants, 33 are four-loop units, 14 are three-loop units, and 14 are two-loop units. There are 133 motor-driven, 63 turbine-driven, and 5 diesel-driven safety-related AFW pumps at these plants.

Table 5.1 provides general SG/AFW pump configuration information for these plants. In general, for two- and three-loop plants, each available pump can feed each SG. For four-loop plants, MDP discharge lines are normally aligned to allow each pump to feed two SGs, whereas turbine- and diesel-driven pump discharge lines are normally aligned to feed all four SGs.

Reactor thermal power and AFW pump design values are listed in Table 5.2. Note that, in general, MDP capacities are typically one-half that of TDPs at the same plant.

Actuation signals for both MDPs and TDPs are provided in Tables 5.3 and 5.4. Explanations of the designated actuation signals follow.

1. Loss of feedwater (FW) – The methods of detecting loss of normal FW vary. Signals based on low main FW pump discharge pressure, main feed pump breaker open, or main feed pump turbine tripped are typical.
2. Loss of emergency or reactor coolant pump (RCP) bus – These signals are typically based on low bus voltage although some plants use RCP tripping as a signal source.
3. Low level in one SG – This signal source is fairly straightforward and is typically based on low level detected by 2/3 or 2/4 level channels for a single SG.
4. Low level in two SGs – Same as low level for one SG, except that the 2/3 or 2/4 logic exists for two SGs.
5. SI – AFW start signal from any SI signal.
6. Other – Includes various other sources of automatic pump starting.

AFW start signals are based on the detection of conditions that, at least usually, indicate extant or imminent degradation of the ability of the SGs to remove heat from the RCS.

Both B&W and Westinghouse plants use the loss of normal FW as a common start source, particularly for MDPs. Note that this start signal is nonsafety-related because the normal FW pumps and associated instrumentation are not safety-related. AFW pump starting from loss of normal FW is an anticipatory start in recognition of the fact that loss of FW would rapidly lead to other automatic starting, such as from low SG level.

Starting of AFW pumps because of emergency bus or RCP bus loss or RCP tripping is the single most common source of pump starting, considering both MDPs and TDPs. Because emergency bus undervoltage start signals necessitate that the bus providing power to the MDPs be reenergized before breaker closure, the MDPs are normally sequenced on, along with other safety-related loads, in conjunction with and following emergency diesel generator starting. Because TDPs are typically started by opening valves that are not dependent on ac power (other than vital ac busses powered off the station batteries through inverters), they are started independently of emergency bus reenergization.

SG low-level starting of AFW pumps is a safety-related start signal that is relied upon for both MDP and TDP starting. TDP starting normally requires low level in two SGs, whereas MDPs typically only require low level in one SG.

Depending on individual plant design, SI signals originate from several different sources, such as low RCS pressure, low PZR level, and high containment pressure. Signals such as these could originate, in turn, from multiple causes, such as excessive

Table 5.1. General AFW configurations

Unit	Number SGs	Number MDPs	Number SGs / MDP	Number TDPs	Number SGs / TDP	Number DDPs	Number SGs / DDP
Arkansas Nuclear One 1	2	1	2	1	2	0	
Crystal River	2	1	2	1	2	0	
Davis-Besse	2	0		2	2	0	
Oconee 1	2	2	1[a]	1	2	0	
Oconee 2	2	2	1[a]	1	2	0	
Oconee 3	2	2	1[a]	1	2	0	
Rancho Seco	2	1	2	1	2	0	
Three Mile Island 1	2	2	2	1	2	0	
Beaver Valley 1	3	2	3	1	3	0	
Beaver Valley 2	3	2	3	1	3	0	
Braidwood 1	4	1	4	0		1	4
Braidwood 2	4	1	4	0		1	4
Byron 1	4	1	4	0		1	4
Byron 2	4	1	4	0		1	4
Callaway	4	2	2[a]	1	4	0	
Catawba 1	4	2	2[a]	1	4	0	
Catawba 2	4	2	2[a]	1	4	0	
Comanche Peak 1	4	2	2[a]	1	4	0	
Comanche Peak 2	4	2	2[a]	1	4	0	
DC Cook 1	4	2	2	1	4	0	
DC Cook 2	4	2	2	1	4	0	
Diablo Canyon 1	4	2	2[a]	1	4	0	
Diablo Canyon 2	4	2	2[a]	1	4	0	
Farley 1	3	2	3	1	3	0	
Farley 2	3	2	3	1	3	0	
Ginna	2	2	2	1	2	0	
Haddam Neck	4	0		2	4	0	
Harris 1	3	2	3	1	3	0	
Indian Point 2	4	2	2	1	4	0	
Indian Point 3	4	2	2	1	4	0	
Kewaunee	2	2	2	1	2	0	
McGuire 1	4	2	2[a]	1	4	0	
McGuire 2	4	2	2[a]	1	4	0	
Millstone 3	4	2	2[a]	1	4	0	

Table 5.1 (continued)

Unit	Number SGs	Number MDPs	Number SGs / MDP	Number TDPs	Number SGs / TDP	Number DDPs	Number SGs / DDP
North Anna 1	3	2	3	1	3	0	
North Anna 2	3	2	3	1	3	0	
Point Beach 1[b]	2	2	1	1	2	0	
Point Beach 2[b]	2	2	1	1	2	0	
Prairie Island 1[b]	2	1	2	1	2	0	
Prairie Island 2[b]	2	1	2	1	2	0	
Robinson 2	3	2	3	1	3	0	
Salem 1	4	2	4	1	4	0	
Salem 2	4	2	4	1	4	0	
San Onofre 1	3	1	3	1	3	0	
Seabrook 1	4	1	4	1	4	0	
Sequoyah 1	4	2	2	1	4	0	
Sequoyah 2	4	2	2	1	4	0	
South Texas 1	4	3	1[a]	1	1[a]	0	
South Texas 2	4	3	1[a]	1	1[a]	0	
Summer	3	2	3	1	3	0	
Surry 1	3	2	3	1	3	0	
Surry 2	3	2	3	1	3	0	
Trojan	4	0		1	4	1	4
Turkey Point 3[b]	3	0		3	3	0	
Turkey Point 4[b]	3	0		3	3	0	
Vogtle 1	4	2	2[a]	1	4	0	
Vogtle 2	4	2	2[a]	1	4	0	
Wolf Creek	4	2	2[a]	1	4	0	
Yankee Rowe	4	2	4	1	4	0	
Zion 1	4	2	4	1	4	0	
Zion 2	4	2	4	1	4	0	

[a] Normal alignment. Pump discharge lines can be realigned to feed all SGs.

[b] Units share one or more AFW pumps. Total of two MDPs, two TDPs at Point Beach and Prarie Island plants; total of three TDPs at Turkey Point plant.

Table 5.2. B&W and Westinghouse plant thermal and pump design ratings

Unit	MW(t) rating	MDP flow (gal/min)	MDP head (psid)	TDP flow (gal/min)	TDP head (psid)	DDP flow (gal/min)	DDP head (psid)
Arkansas Nuclear One 1	2568	640	1224	770	1223		
Crystal River	2542	740	1300	740	1300		
Davis-Besse	2772			1050	1050		
Oconee 1	2568						
Oconee 2	2568						
Oconee 3	2568						
Rancho Seco	2772	840	1150[a]	840	1150[a]		
Three Mile Island 1	2568	460	1170	920	1170		
Beaver Valley 1	2660	350	1168	700	1168		
Beaver Valley 2	2652	375	1196	750	1196		
Braidwood 1	3411	990	1452			990	1452
Braidwood 2	3411	990	1452			990	1452
Byron 1	3411	990	1452			990	1452
Byron 2	3411	990	1452			990	1452
Callaway	3425	575	1387	1145	1495		
Catawba 1	3411	500	1391	1000	1394		
Catawba 2	3411	500	1391	1000	1394		
Comanche Peak 1	3425	490	1430	985	1452		
Comanche Peak 2	3425	490	1430	985	1452		
DC Cook 1	3250	450	1176	900	1176		
DC Cook 2	3250	450	1176	900	1176		
Diablo Canyon 1	3338	490	1300	930	1300		
Diablo Canyon 2	3411	490	1300	930	1300		
Farley 1	2652	350	1233	700	1229		
Farley 2	2652	350	1233	700	1229		
Ginna	1520	200	1235	400	1300		
Haddam Neck	1825			450	1075		
Harris 1	2775	450	1265	900	1265		
Indian Point 2	2758	400	1352	940	1352		
Indian Point 3	3025	400	1352	940	1352		
Kewaunee	1650	240	1235	240	1235		
McGuire 1	3411	450	1387	900	1387		
McGuire 2	3411	450	1387	900	1387		

Table 5.2 (continued)

Unit	MW(t) rating	MDP flow (gal/min)	MDP head (psid)	TDP flow (gal/min)	TDP head (psid)	DDP flow (gal/min)	DDP head (psid)
Millstone 3	3411	575	1289	1150	1289		
North Anna 1	2775	340	1250	340	1430		
North Anna 2	2775	340	1250	340	1430		
Point Beach 1	1518	200		400			
Point Beach 2	1518	200		400			
Prairie Island 1	1721	220	1285	220	1285		
Prairie Island 2	1721	220	1285	220	1285		
Robinson 2	2300	300	1300	600	1300		
Salem 1	3338	440	1300	980	1550		
Salem 2	3411	440	1300	980	1550		
San Onofre 1	1347	235	1035	300	1088		
Seabrook 1	3411	710	1320	710	1320		
Sequoyah 1	3411	465	1257	920	1127		
Sequoyah 2	3411	465	1257	920	1127		
South Texas 1	3800						
South Texas 2	3800						
Summer	2775	400	1430	900	1473		
Surry 1	2546	350	1183	700	1183		
Surry 2	2546	350	1183	700	1183		
Trojan	3423			960	1473	960	1473
Turkey Point 3	2200			600	1203		
Turkey Point 4	2200			600	1203		
Vogtle 1	3425	630	1517	1175	1517		
Vogtle 2	3425	630	1517	1175	1517		
Wolf Creek	3411	575	1387	1145	1495		
Yankee Rowe	600						
Zion 1	3391	495	1343	990	1343		
Zion 2	3391	495	1343	990	1343		

[a] Value cited is design discharge pressure, not total developed head.

Table 5.3. AFW MDP actuation signals for Westinghouse and B&W plants

Unit	Loss of FW	Loss of emergency or RCP bus	Low level, one SG	Low level, two SGs	SI	Other
			B&W Plants			
Arkansas Nuclear One 1	Yes	Yes	Yes	No	Yes	Yes
Crystal River	Yes	Yes	Yes	No	Yes	Yes
Davis-Besse						
Oconee 1	Yes	No	No	No	No	Yes
Oconee 2	Yes	No	No	No	No	Yes
Oconee 3	Yes	No	No	No	No	Yes
Rancho Seco	Yes	Yes	No	No	Yes	No
Three Mile Island 1	Yes	Yes	No	No	No	No
B&W Total	7	4	2	0	3	5
			Westinghouse Plants			
Beaver Valley 1	Yes	Yes	No	Yes	Yes	Yes
Beaver Valley 2	Yes	Yes	No	Yes	Yes	Yes
Braidwood 1	No	Yes	Yes	No	Yes	No
Braidwood 2	No	Yes	Yes	No	Yes	No
Byron 1	No	Yes	Yes	No	Yes	No
Byron 2	No	Yes	Yes	No	Yes	No
Callaway	Yes	Yes	Yes	No	Yes	No
Catawba 1	Yes	Yes	Yes	No	Yes	No
Catawba 2	Yes	Yes	Yes	No	Yes	No
Comanche Peak 1	Yes	Yes	Yes	No	Yes	No
Comanche Peak 2	Yes	Yes	Yes	No	Yes	No
DC Cook 1	Yes	Yes	Yes	No	Yes	No
DC Cook 2	Yes	Yes	Yes	No	Yes	No
Diablo Canyon 1	Yes	Yes	Yes	No	Yes	No
Diablo Canyon 2	Yes	Yes	Yes	No	Yes	No
Farley 1	Yes	Yes	Yes	No	Yes	No
Farley 2	Yes	Yes	Yes	No	Yes	No
Ginna	Yes	Yes	Yes	No	Yes	No
Haddam Neck						
Harris 1	Yes	Yes	Yes	No	Yes	No
Indian Point 2	Yes	Yes	Yes	No	Yes	No

Table 5.3 (continued)

Unit	Loss of FW	Loss of emergency or RCP bus	Low level, one SG	Low level, two SGs	SI	Other
Indian Point 3	Yes	Yes	Yes	No	Yes	No
Kewaunee	Yes	Yes	Yes	No	Yes	No
McGuire 1	Yes	Yes	Yes	No	Yes	No
McGuire 2	Yes	Yes	Yes	No	Yes	No
Millstone 3	No	Yes	Yes	No	Yes	Yes
North Anna 1	Yes	Yes	Yes	No	Yes	No
North Anna 2	Yes	Yes	Yes	No	Yes	No
Point Beach 1	Yes	No	Yes	No	Yes	No
Point Beach 2	Yes	No	Yes	No	Yes	No
Prairie Island 1	Yes	Yes	Yes	No	Yes	No
Prairie Island 2	Yes	Yes	Yes	No	Yes	No
Robinson 2	Yes	Yes	Yes	No	Yes	No
Salem 1	Yes	Yes	Yes	No	Yes	No
Salem 2	Yes	Yes	Yes	No	Yes	No
San Onofre 1	No	No	No	Yes	No	No
Seabrook 1	No	Yes	Yes	No	Yes	No
Sequoyah 1	Yes	Yes	Yes	No	Yes	No
Sequoyah 2	Yes	Yes	Yes	No	Yes	No
South Texas 1	No	Yes	Yes	No	Yes	No
South Texas 2	No	Yes	Yes	No	Yes	No
Summer	Yes	Yes	Yes	No	Yes	No
Surry 1	Yes	Yes	Yes	No	Yes	No
Surry 2	Yes	Yes	Yes	No	Yes	No
Trojan						
Turkey Point 3						
Turkey Point 4						
Vogtle 1	Yes	Yes	Yes	No	Yes	No
Vogtle 2	Yes	Yes	Yes	No	Yes	No
Wolf Creek	Yes	Yes	Yes	No	Yes	No
Yankee Rowe	No	No	No	No	No	No
Zion 1	No	Yes	Yes	No	Yes	No
Zion 2	No	Yes	Yes	No	Yes	No
Westinghouse Total	37	45	45	3	47	3

Table 5.4. AFW TDP actuation signals for Westinghouse and B&W plants

Unit	Loss of FW	Loss of emergency or RCP bus	Low level, one SG	Low level, two SGs	SI	Other
			B&W Plants			
Arkansas Nuclear One 1	Yes	Yes	Yes	No	Yes	Yes
Crystal River	Yes	Yes	Yes	No	Yes	Yes
Davis-Besse	Yes	Yes	Yes	No	No	Yes
Oconee 1	Yes	No	No	No	No	Yes
Oconee 2	Yes	No	No	No	No	Yes
Oconee 3	Yes	No	No	No	No	Yes
Rancho Seco	Yes	Yes	No	No	Yes	No
Three Mile Island 1	Yes	Yes	No	No	No	No
B&W Total	9	7	6	4	8	12
			Westinghouse Plants			
Beaver Valley 1	No	Yes	Yes	No	No	No
Beaver Valley 2	No	Yes	Yes	No	No	No
Braidwood 1						
Braidwood 2						
Byron 1						
Byron 2						
Callaway	No	Yes	No	Yes	No	No
Catawba 1	No	Yes	No	Yes	No	No
Catawba 2	No	Yes	No	Yes	No	No
Comanche Peak 1	No	Yes	No	Yes	No	No
Comanche Peak 2	No	Yes	No	Yes	No	No
DC Cook 1	No	Yes	Yes	No	No	No
DC Cook 2	No	Yes	Yes	No	No	No
Diablo Canyon 1	No	Yes	No	Yes	No	No
Diablo Canyon 2	No	Yes	No	Yes	No	No
Farley 1	No	Yes	No	Yes	No	No
Farley 2	No	Yes	No	Yes	No	No
Ginna	No	Yes	No	Yes	No	No
Haddam Neck	Yes	No	Yes	No	No	No
Harris 1	No	Yes	No	Yes	No	No
Indian Point 2	No	Yes	No	Yes	No	No

Table 5.4 (continued)

Unit	Loss of FW	Loss of emergency or RCP bus	Low level, one SG	Low level, two SGs	SI	Other
Indian Point 3	No	Yes	No	Yes	No	No
Kewaunee	No	Yes	No	Yes	No	No
McGuire 1	No	Yes	No	Yes	No	No
McGuire 2	No	Yes	No	Yes	No	No
Millstone 3	No	Yes	No	Yes	No	No
North Anna 1	Yes	Yes	Yes	No	Yes	No
North Anna 2	Yes	Yes	Yes	No	Yes	No
Point Beach 1	No	Yes	No	Yes	No	No
Point Beach 2	No	Yes	No	Yes	No	No
Prairie Island 1	Yes	Yes	Yes	No	Yes	No
Prairie Island 2	Yes	Yes	Yes	No	Yes	No
Robinson 2	No	Yes	No	Yes	No	No
Salem 1	No	Yes	No	Yes	No	No
Salem 2	No	Yes	No	Yes	No	No
San Onofre 1	No	Yes	No	Yes	No	No
Seabrook 1	No	Yes	Yes	No	Yes	No
Sequoyah 1	Yes	Yes	No	Yes	Yes	No
Sequoyah 2	Yes	Yes	No	Yes	Yes	No
South Texas 1	No	No	Yes	No	Yes	No
South Texas 2	No	No	Yes	No	Yes	No
Summer	No	Yes	No	Yes	No	No
Surry 1	No	Yes	No	Yes	No	No
Surry 2	No	Yes	No	Yes	No	No
Trojan	Yes	Yes	Yes	No	Yes	No
Turkey Point 3	Yes	Yes	Yes	No	Yes	No
Turkey Point 4	Yes	Yes	Yes	No	Yes	No
Vogtle 1	No	Yes	No	Yes	No	No
Vogtle 2	No	Yes	No	Yes	No	No
Wolf Creek	No	Yes	No	Yes	No	No
Yankee Rowe						
Zion 1	No	Yes	No	Yes	Yes	No
Zion 2	No	Yes	No	Yes	Yes	No
Westinghouse Total	18	50	18	33	17	6

cooldown/depressurization of the RCS caused by excessive steam flow, SG tube rupture in which the loss of RCS inventory exceeds makeup capacity, or a loss-of-coolant accident.

Table 5.5 lists the numbers of and types of valve operators in the AFW system at the B&W and Westinghouse plants. Some valves with power operators, as well as the AFW pumps, have automatic actions to perform with AFW system starting. All TDPs depend on one or more steam supply valves, or the turbine's T&T valve, to open to start the turbine. Depending on individual plant design, discharge valves (including those in the recirculation or other alternative flow paths) may be required to open automatically, control pressure or flow, or close on automatic AFW system actuation. Discharge valves are also required to isolate flow for certain conditions at some plants (e.g., the detection of a faulted SG). Pump suction valves at some plants are required to automatically reposition on detection of low suction pressure to ensure the availability of a source of water for the pumps.

As Table 5.5 shows, the total number of air-operated valves (AOVs) and motor-operated valves (MOVs) in both steam supply and pump discharge piping applications are almost equal at Westinghouse plants, whereas the B&W plants incorporate more MOVs than AOVs. A few solenoid-operated valves (SOVs) and electrohydraulic-operated valves (EHOVs) are in both types of applications. Note that neither T&T valves (normally dc motor operated) nor GVs (normally with hydraulic actuators) are included in this list. Pump suction valves with power operators are predominately motor operated.

Note that not all valves with power operators have automatic functions, but rather may depend on remote operator action. On the other hand, some valves, such as pump-discharge pressure-control valves, may have an automatic control function, with no provision for remote operator control.

Table 5.6 provides a breakdown of the operator types and normal standby positions for discharge flow-control valves and discharge isolation valves. Note that some plants do not have power-operated isolation valves other than the flow-control valves.

Table 5.7 includes a designation of the type of minimum flow restriction device used and identification of the availability of a full ("full flow" meaning design flow) test loop. Determination of both characteristics was based on FSAR flow diagrams. Note that some plants for which a full-flow test loop is available may not use the full-flow test loop for routine pump testing. Furthermore, some plants without full-flow test loops may run their AFW pumps at full flow periodically (typically at each cold shutdown) in conjunction with their pump and valve in-service test program.

Devices used for minimum flow restriction are normally orifices and/or control valves. At some plants, the control valves in the minimum flow lines automatically isolate or open based on control signals, while at others the valves are set at fixed positions.

Table 5.8 identifies the required inventory of condensate supply and the type of switchover to the alternate suction source that is provided. Where automatic switch-over is provided, initiation is normally by low pump suction pressure switches.

Table 5.5. Numbers of B&W and Westinghouse plant valve operator types

Unit	Discharge valves				Suction valves		Steam supply valves			
	AOV	MOV	SOV	EHOV	AOV	MOV	AOV	MOV	SOV	EHOV
B&W Plants										
Arkansas Nuclear One 1	1	6	4	0	0	6	0	5	2	0
Crystal River	0	4	4	0	0	4	0	4	0	0
Davis-Besse	0	8	0	0	0	2	0	4	0	0
Oconee 1	4	7	0	0	0	2	2	2	0	0
Oconee 2	4	7	0	0	0	2	2	2	0	0
Oconee 3	4	7	0	0	0	2	2	2	0	0
Rancho Seco	3	6	2	0	0	0	0	3	0	0
Three Mile Island 1	5	2	0	0	0	2	3	4	0	0
B&W Total	21	47	10	0	0	20	9	26	2	0
Westinghouse Plants										
Beaver Valley 1	3	9	0	0	0	0	2	1	0	0
Beaver Valley 2	0	0	0	6	0	0	0	0	6	0
Braidwood 1	10	8	0	0	0	4	0	0	0	0
Braidwood 2	10	8	0	0	0	4	0	0	0	0
Byron 1	10	8	0	0	0	4	0	0	0	0
Byron 2	10	8	0	0	0	4	0	0	0	0
Callaway	4	4	0	0	0	7	2	0	0	0
Catawba 1	6	8	0	0	0	7	2	0	0	0
Catawba 2	6	8	0	0	0	7	2	0	0	0
Comanche Peak 1	10	8	0	0	0	2	2	0	4	0
Comanche Peak 2	10	8	0	0	0	2	2	0	4	0
DC Cook 1	7	8	0	0	0	3	0	2	0	0
DC Cook 2	7	8	0	0	0	3	0	2	0	0
Diablo Canyon 1	0	4	0	4	0	2	0	2	0	0
Diablo Canyon 2	0	4	0	4	0	2	0	2	0	0
Farley 1	6	9	0	0	0	5	5	0	0	0
Farley 2	6	9	0	0	0	5	5	0	0	0
Ginna	7	5	0	0	1	3	0	2	0	0
Haddam Neck	4	1	0	0	0	0	2	0	0	0
Harris 1	0	8	0	8	0	8	0	2	0	0
Indian Point 2	10	0	0	0	4	0	3	0	0	0
Indian Point 3	10	0	0	0	4	0	3	0	0	0

Table 5.5 (continued)

Unit	Discharge valves				Suction valves		Steam supply valves			
	AOV	MOV	SOV	EHOV	AOV	MOV	AOV	MOV	SOV	EHOV
Kewaunee	2	2	0	0	0	0	0	2	0	0
McGuire 1	11	8	0	0	0	8	2	0	0	0
McGuire 2	11	8	0	0	0	8	2	0	0	0
Millstone 3	2	4	12	0	2	0	3	3	0	0
North Anna 1	5	4	0	0	0	0	2	0	0	0
North Anna 2	5	4	0	0	0	0	2	0	0	0
Point Beach 1	3	4	0	0	0	0	0	2	0	0
Point Beach 2	3	4	0	0	0	0	0	2	0	0
Prairie Island 1	0	6	0	0	0	4	1	2	0	0
Prairie Island 2	0	6	0	0	0	4	1	2	0	0
Robinson 2	0	8	0	3	0	0	0	3	0	0
Salem 1	10	0	0	0	3	0	1	0	0	0
Salem 2	10	0	0	0	3	0	1	0	0	0
San Onofre 1	4	2	0	0	0	0	2	0	0	0
Seabrook 1	4	0	0	0	0	0	0	0	0	2
Sequoyah 1	8	0	0	0	0	8	0	4	0	0
Sequoyah 2	8	0	0	0	0	8	0	4	0	0
South Texas 1	4	8	0	0	0	0	0	1	1	0
South Texas 2	4	8	0	0	0	0	0	1	1	0
Summer	9	0	0	0	0	6	1	2	0	0
Surry 1	0	6	0	0	0	0	2	0	0	0
Surry 2	0	6	0	0	0	0	2	0	0	0
Trojan	0	8	0	0	0	2	4	1	0	0
Turkey Point 3	6	0	0	0	0	0	0	3	0	0
Turkey Point 4	6	0	0	0	0	0	0	3	0	0
Vogtle 1	0	10	0	0	0	3	0	3	0	0
Vogtle 2	0	10	0	0	0	3	0	3	0	0
Wolf Creek	4	4	0	0	0	3	2	0	0	0
Yankee Rowe	4	3	0	0	0	0	1	0	0	0
Zion 1	8	8	0	0	0	5	0	2	0	0
Zion 2	8	8	0	0	0	5	0	2	0	0
Westinghouse Total	275	272	12	25	17	139	59	58	16	2

Table 5.6. Flow control and isolation valve types, normal positions[a]

Unit	FCV operator type	FCV normal position	Other isolation valve operator type	Isolation valve normal position
Arkansas Nuclear One 1	SOV	NO	MOV	NO
Crystal River	MOV	NO	SOV	NO
Davis-Besse	MOV	NO	MOV	NO/NC
Oconee 1	AOV	NC	MOV	NO
Oconee 2	AOV	NC	MOV	NO
Oconee 3	AOV	NC	MOV	NO
Rancho Seco	AOV/SOV	NO	MOV	NC
Three Mile Island 1	AOV	NO	MOV	NO
Beaver Valley 1	MOV	NO	MOV	NO
Beaver Valley 2	EHOV	NO		
Braidwood 1	AOV	NO	MOV	NO
Braidwood 2	AOV	NO	MOV	NO
Byron 1	AOV	NO	MOV	NO
Byron 2	AOV	NO	MOV	NO
Callaway	MOV/AOV	NO		
Catawba 1	AOV	NO	MOV	NO/NC
Catawba 2	AOV	NO	MOV	NO/NC
Comanche Peak 1	AOV	NO	MOV	NO
Comanche Peak 2	AOV	NO	MOV	NO
DC Cook 1	MOV	NO		
DC Cook 2	MOV	NO		
Diablo Canyon 1	EHOV/MOV	NO/NC		
Diablo Canyon 2	EHOV/MOV	NO/NC		
Farley 1	AOV	NC	MOV	NO
Farley 2	AOV	NC	MOV	NO
Ginna	MOV/AOV	NO/NC		
Haddam Neck	AOV	NC		
Harris 1	EHOV	NO	MOV	NO
Indian Point 2	AOV	NO		
Indian Point 3	AOV	NO		
Kewaunee	AOV/MOV	NO		
McGuire 1	AOV	NO	MOV	NO
McGuire 2	AOV	NO	MOV	NO
Millstone 3	SOV	NO	SOV/MOV	NO
North Anna 1	AOV/MOV	NO		

Table 5.6 (continued)

Unit	FCV operator type	FCV normal position	Other isolation valve operator type	Isolation valve normal position
North Anna 2	AOV/MOV	NO		
Point Beach 1	MOV	NO		
Point Beach 2	MOV	NO		
Prairie Island 1	MOV	NO	MOV	NO
Prairie Island 2	MOV	NO	MOV	NO
Robinson 2	EHOV	NC	MOV	NC
Salem 1	AOV	NO		
Salem 2	AOV	NO		
San Onofre 1	AOV	NO		
Seabrook 1	AOV	NO		
Sequoyah 1	AOV	NC		
Sequoyah 2	AOV	NC		
South Texas 1	MOV	NO	MOV	NC
South Texas 2	MOV	NO	MOV	NC
Summer	AOV	NO	AOV	NO
Surry 1	MOV	NO		
Surry 2	MOV	NO		
Trojan	MOV	NO		
Turkey Point 3	AOV	NC		
Turkey Point 4	AOV	NC		
Vogtle 1	MOV	NO		
Vogtle 2	MOV	NO		
Wolf Creek	AOV/MOV	NO		
Yankee Rowe	MOV	NO		
Zion 1	AOV	NO	MOV	NO
Zion 2	AOV	NO	MOV	NO

[a] FCV – Flow-control valve
AOV – Air-operated valve
EHOV – Electrohydraulic-operated valve
MOV – Motor-operated valve
SOV – Solenoid-operated valve
NO – Normally open
NC – Normally closed

Table 5.7. Test loop and recirculation control types

Unit	Full flow test loop available?	Miniflow flow restriction type
Arkansas Nuclear One 1	Yes	Orifice
Crystal River	No	Line size
Davis-Besse	Yes	Orifice
Oconee 1	TDP only	Orifice/CV
Oconee 2	TDP only	Orifice/CV
Oconee 3	TDP only	Orifice/CV
Rancho Seco	Yes	Orifice
Three Mile Island 1	No	Orifice/line size
Beaver Valley 1	Partial	Orifice/CV
Beaver Valley 2	No	Orifice
Braidwood 1	No	Orifice
Braidwood 2	No	Orifice
Byron 1	No	Orifice
Byron 2	No	Orifice
Callaway	No	Orifice
Catawba 1	Yes	CV
Catawba 2	Yes	CV
Comanche Peak 1	Yes	Orifice
Comanche Peak 2	Yes	Orifice
DC Cook 1	Yes	CV
DC Cook 2	Yes	CV
Diablo Canyon 1	No	Orifice
Diablo Canyon 2	No	Orifice
Farley 1	Yes	Orifice/CV
Farley 2	Yes	Orifice/CV
Ginna	No	Orifice/CV
Haddam Neck	No	OrificeS
Harris 1	No	Orifice/CV
Indian Point 2	Yes	Orifice/CV
Indian Point 3	Yes	Orifice/CV
Kewaunee	No	
McGuire 1	Yes	CV
McGuire 2	Yes	CV
Millstone 3	No	Orifice

Table 5.7 (continued)

Unit	Full flow test loop available?	Miniflow flow restriction type
North Anna 1	No	Orifice
North Anna 2	No	Orifice
Point Beach 1	No	Orifice/CV
Point Beach 2	No	Orifice/CV
Prairie Island 1	No	Orifice
Prairie Island 2	No	Orifice
Robinson 2	No	Orifice
Salem 1	No	Orifice/CV
Salem 2	No	Orifice/CV
San Onofre 1	No	Orifice
Seabrook 1	No	Orifice
Sequoyah 1	No	Orifice
Sequoyah 2	No	Orifice
South Texas 1	Yes	CV
South Texas 2	Yes	CV
Summer	No	Orifice
Surry 1	No	Orifice
Surry 2	No	Orifice
Trojan	No	Orifice
Turkey Point 3	No	Orifice
Turkey Point 4	No	Orifice
Vogtle 1	No	Orifice/CV
Vogtle 2	No	Orifice/CV
Wolf Creek	No	Orifice
Yankee Rowe		CV
Zion 1	No	Orifice
Zion 2	No	Orifice

Table 5.8. Normal suction supply quantity and suction switchover method

Unit	Technical Specification required supply (gal x 10^3)	Auto or manual suction switchover
Arkansas Nuclear One 1	107	Manual
Crystal River	150	Manual
Davis-Besse	250	Auto
Oconee 1	72	Manual
Oconee 2	72	Manual
Oconee 3	72	Manual
Rancho Seco	250	Manual
Three Mile Island 1	150	Manual
Beaver Valley 1	140[a]	Manual
Beaver Valley 2	127	Manual
Braidwood 1	200	Auto
Braidwood 2	200	Auto
Byron 1	200	Auto
Byron 2	200	Auto
Callaway	281	Auto
Catawba 1	225	Auto
Catawba 2	225	Auto
Comanche Peak 1	276[a]	Manual
Comanche Peak 2	276[a]	Manual
DC Cook 1		Manual
DC Cook 2		Manual
Diablo Canyon 1	178	Manual
Diablo Canyon 2	178	Manual
Farley 1	150	Manual
Farley 2	150	Manual
Ginna	22.5	Manual
Haddam Neck	130	Manual
Harris 1	240	Manual
Indian Point 2	360	Manual
Indian Point 3	360	Manual
Kewaunee	30	Manual
McGuire 1	297.5 Max [a]	Auto
McGuire 2	297.5 Max [a]	Auto
Millstone 3	334	Manual
North Anna 1	110	Manual

Table 5.8 (continued)

Unit	Technical Specification required supply (gal x 10^3)	Auto or manual suction switchover
North Anna 2	110	Manual
Point Beach 1	90	Manual
Point Beach 2	90	Manual
Prairie Island 1	100	Manual
Prairie Island 2	100	Manual
Robinson 2	35	Manual
Salem 1	200	Manual
Salem 2	200	Manual
San Onofre 1	190	Manual
Seabrook 1	212	Manual
Sequoyah 1	190	Auto
Sequoyah 2	190	Auto
South Texas 1	518	Manual
South Texas 2	518	Manual
Summer	173	Auto
Surry 1	96	Manual
Surry 2	96	Manual
Trojan	450[a]	Manual
Turkey Point 3	185	Manual
Turkey Point 4	185	Manual
Vogtle 1	340	Manual
Vogtle 2	340	Manual
Wolf Creek	281	Auto
Yankee Rowe		
Zion 1	170	Manual
Zion 2	170	Manual

[a] Value cited is from unit FSAR.

6. RESULTS, CONCLUSIONS, AND RECOMMENDATIONS

The Phase I study of the AFW system consisted of three primary parts:

1. A detailed review of the AFW system design and operating/monitoring practices of a plant owned by a cooperating utility was conducted.
2. Operational failure events for AFW system components from three failure data base sources were reviewed and analyzed.
3. A summary review and tabulation of AFW system configurations and design information available from individual plant FSARs and Technical Specifications was completed.

The detailed results of these three parts are provided in Chaps. 3, 4, and 5. The combined results of parts 1 and 2 given previously (part 3 was performed primarily for general information and to support the studies of parts 1 and 2) provide the basis for the following observations and recommendations.

6.1 RELATIVE SIGNIFICANCE OF AFW COMPONENTS

To gain some perspective concerning the more significant contributors to AFW system degradation, the historical failure data were relied upon heavily. Although the available failure data have substantial limitations, even with the uniformity of characterization afforded by the ORNL compilation, they are useful as a rough indicator of relative trends.

6.1.1 Results

The review of the failure data indicated that a few types of AFW system components were responsible for a large fraction of system degradation. Turbine drivers (including the turbine, its T&T valve, GV, and associated control circuitry), valve air operators, and valve motor operators accounted for over one-half of the system degradation. Problems with the turbine drivers alone accounted for 27% of the system degradation. Valve air operators, motor operators, pumps, and check valves were responsible for 14, 13, 12, and 9% of system degradation, respectively.

The AFW system degradation associated with turbine drivers is particularly noteworthy because there is a total population of only 51 TDPs at the plants in the failure data base, compared with 77 MDPs, 315 AOVs, and 438 MOVs. Of the turbine failures, only a very small portion (<10%) involved failures or degradation of the turbine itself. The majority of the failures involved problems with turbine auxiliaries (primarily I&C/governor control and T&T valve problems). On-demand failures of turbines were responsible for almost one-fourth of all turbine-related degradation and for over one-third of all on-demand failure degradation.

6.1.2 Conclusions

The turbine drive is the single component type that stands out in the failure data as the most significant source of AFW system degradation. It is also, by far, the single largest source of system degradation associated with on-demand failures. More specifically, problems associated with the governor and controls for TDPs have been very significant sources of degradation.

The other significant AFW system component types, including pumps, check valves, and air and motor operators have been or are being reviewed in detail as a part of the NPAR program. Because of the significance of the turbine to historical AFW system degradation, as well as the fact that the turbines used on AFW pumps are similar to those used on some safety-related pumps in boiling-water reactor (BWR) plants, further review of turbine drives in general, and more specifically the turbine controls, appears warranted.

6.2 ADEQUACY OF CURRENT MONITORING PRACTICES

In keeping with the goals of the NPAR Program, one of the driving forces behind the reviews was an attempt to ascertain the adequacy of current monitoring practices. The extent to which failure sources could be detected by the surveillance and operating practices at an individual plant was determined as a part of the Plant A review. The extent to which actual failure events have been detected by programmatic monitoring practices, through routine observation, and during demand events was ascertained during the review of historical failure data. The results from the combined reviews provide important insights into which types of failures have occurred, how those failures have been detected historically, and how well failures could be detected by existing monitoring methods.

In conjunction with the review of the Plant A procedures, the frequency of test-related actuation of AFW system components was estimated. The number of test actuations was tabulated to give an indication of (1) the likelihood of degradation or failure of a component being identified (i.e., whether that particular component was being verified operable or not), and (2) the extent of service wear that may be associated with testing.

The results available from the reviews of: (1) Plant A failure source detectability, (2) historical failure records, and (3) the frequency of test-related actuation provide a combination of information that is useful for making a general assessment of monitoring requirements and implementing program efficiency. By comparing the relative significance of a particular component, from both a historical failure and identified failure nondetectability perspective, to the relative attention given the component by the Plant A monitoring program, a summary indication of the extent of monitoring optimization can be gathered.

6.2.1 Results

6.2.1.1 Detectability of failure/degradation

The types of failure sources or conditions that were found not to be detectable by current monitoring or routine operating practices at Plant A largely fall into two categories. The categories and examples of each follow.

1. A component or group of components is unable to perform as required under design basis accident or off-normal conditions even though the general performance is demonstrated under more normal conditions.

   Example:
   Failure Condition: An MDP is degraded and unable to deliver required flow with the associated SGs at maximum postaccident/transient pressure.
   Nondetectability: The MDPs are verified to be operable by testing under recirculation flow only (at ~10% of design flow). Although check valves in the discharge flow path are verified operable by delivery of the required *flow* to the SGs, there is no requirement for, nor monitoring of, SG, pump suction, and pump discharge pressure.

2. A component or group of components is unable to perform as required because of failures of related I&C that are not observed during routine testing or operation.

   Example:

   Failure Condition: The SG BDIVs fail to close following TDP start because of failure of contacts associated with a stem-operated limit switch for the turbine T&T valve.

   Nondetectability: SG BDIVs are not verified to close in response to starting of the TDP by any testing.

Note that some of the mentioned nondetectable failure conditions actually apply to both categories; that is, failures in I&C circuitry that would only be challenged under design-basis accident or off-normal conditions. For example, there is no verification that the SSVs can complete the automatic steam supply transfer if the normal steam supply source (SG A) is not available to drive the TDP (as would be the case following an event in which SG A was depressurized, such as a FW line break). A number of I&C components that are not tested (relays, contacts) must operate properly to accomplish the transfer.

6.2.1.2 Failure history

The review of historical failure data provided a broader, but less detailed perspective of the ability of current monitoring programs and routine observations to detect degradation/failure of AFW system components. Because design-basis challenges of most components are extremely rare, the historical failure data, even for demand-related failures, are not good indicators of the ability of components to perform under design-basis conditions. Therefore, the data are not particularly useful as a means of confirming the observations made in the Plant A review relative to the ability of components to perform as required under design-basis/off-normal conditions (see the discussion under Sect. 6.2.1.1, category 1, above). The different perspective offered by the failure data review does, however, complement the observations made as a part of the Reference Plant review because about one-half of the degradation detected during demand events was caused by I&C-related failures, whereas, as noted in category 2 of Sect. 6.2.1.1, many of the nondetectable failure conditions that could exist at Plant A were I&C related.

The failure data review found that about one-fifth of overall AFW system degradation was detected during demand events. This finding is also complementary to the results of the Plant A review, in which a significant number of failure conditions were found that would not be detectable by programmatic monitoring or by routine observations.

6.2.1.3 Test frequency

Table 6.1 provides a summary of estimated test-related actuation frequency for various AFW system components at the Plant A. Some components were found to be actuated, for testing purposes, about an order of magnitude more frequently than others.

Note that the number of actuations cited in the table include actuations that result from two sources: (1) those required in support of testing that demonstrates operability of the individual component and (2) actuations that occur in conjunction with testing other components or systems. For the components tested least frequently, the majority or all of the actuations come from the former, while for many of the components most frequently actuated, the majority of the actuations come about as a result of the latter.

Table 6.1. Estimated test frequency for Plant A AFW system components

Component	Number of test actuations per year[a]
SCVs C-3, -4,	13 Partial, 2 full
SCV C-5	11 Partial, 4 full
MOV-1, -2, -3, -4	5 Full
MOV-5, -6, -7, -8	5 Full
MDPs	12 Recirc / 2 full flow
TDP	11 Recirc / 4 full flow
T&T valve	43 Full
MCVs C-6 , -8	14 Full
MCV C-10	15 Full
CMCVs C-1, -2	39 Partial, 1 full
DCVs C-7, -9	2 Full
DCV C-11	4 Full
LCV-1, -3, -5, -7	23 Full
LCV-1A, -3A, -5A, -7A	21 Full
LCV-2, -4, -6, -8	26 Full
LCVCVs C-13, -15, -17, -19	2 Full
LCVCVs C-12, -14, -16, -18	4 Full
MFCVs C-21, -22, -24, -25	6 Full
FWCVs C-20, -23, -26, -27	0 Full
FWIV-1, -2, -3, -4	5 Full
BDV-1, -2, -3, -4	29 Full
MOV-11, -12	25 Full
MOV-9 / MOV-10	29 / 25 Full

[a]All test actuation frequencies are estimated based on an assumed 18-month fuel cycle length.

6.2.2 Conclusions

The fraction of AFW system degradation that has historically been found during demand events, as well as the number and types of failure and degradation sources that were found to not be detectable by the monitoring methods in place at Plant A, indicate the need for improvement in certain aspects of the current monitoring practices. Although no guidelines establish an acceptable level of fraction of failures detected during demand, the rate indicated by the failure data review (~18% of all system degradation was detected during demand conditions) appears excessive. This is particularly the case for certain component types and parts (e.g., the pump driver group and TDP I&C/governor controls).

It was also found in the Plant A review that the ability of some components to function as required under design-basis or off-normal conditions is not verified periodically. This was found to be the case particularly where multiple component interaction is involved. Decidedly adverse effects could result from routine testing of some of these currently nontested areas (such as checking the ability of the AFW pumps to successfully negotiate the suction transfer from the CST to ESW), whereas other areas could be checked fairly easily with little additional effort and no adverse consequences (such as verifying pump capability by monitoring additional parameters during the full stroking of check valves in the discharge flow path).

When the test frequency and the information that can be gathered from the various test-related actuations of AFW system components are considered in light of historical failure experience and areas of nondetectability identified by the review of the Plant A monitoring program, it is apparent that both the test requirements and the actual implementation of those requirements are not optimized. While an attempt to tabulate areas of nonoptimization has not been made, the following example is indicative of the lack of test optimization.

> Example
> The historical failure data showed that over half of the system degradation associated with turbine failures was caused by I&C and governor control related problems. (Remember that turbine-related failures were the single most significant source of system degradation.) Yet there is no specific Technical Specification requirement for the calibration of the governor control system. At Plant A, the governor is calibrated, according to ST-27, on a refueling frequency. However, in the "Scope" section, the procedure notes that "This instruction does not satisfy any Technical Specification surveillance requirements" and "This instruction is intended to be performed during each refueling outage but may be performed in whole or in part as needed." In the ORNL compilation of nondetectable failure sources, it was assumed that this procedure was conducted in full each refueling outage. Because there is no *requirement* to conduct this testing, the testing may not be conducted for an indefinite period. Note that some plants do not even designate the governor calibration procedure as a "Surveillance Procedure." In fact, because Technical Specifications do not require the calibration, it is to be expected that governor calibration procedures would normally not be designated as such. As noted in the discussion for the TDP for Plant A, a number of turbine-related I&C failure sources (ignoring governor-related areas) are also not detectable by the existing monitoring program.

Thus, the single largest source of turbine-related problems is monitored directly on a refueling frequency (roughly every 12 to 18 months) *at best*.

On the other hand, the T&T valve, which was a less significant source of turbine-related problems, is estimated to be stroked over 40 times a year in support of testing at

Plant A. Ironically, worn linkage was identified as the source of many of the T&T valve problems in the failure data. Because a substantial portion of T&T valve operation occurs from testing, testing itself may be a significant source of T&T valve problems.

In light of those observations, it appears that enhancements in current monitoring requirements and practices are warranted. Enhancements should focus on

1. optimizing the testing requirements/programs to reduce testing of components that have historically not been major contributors to system degradation and for which the current testing provides little useful information, while at the same time focusing more attention on those components and functional areas that have been more significant historically;
2. specifically improving the monitoring of I&C portions of the AFW system; and
3. better verifying the ability of components to function under design-basis/off-normal conditions.

6.3 RECOMMENDATIONS

This report concludes with three recommendations:

1. Conduct a Phase II study of the AFW system. The Phase II study should include the following:

   a. the detailed identification of areas of current monitoring/operating practices and requirements that are not optimal for maintaining the availability and demonstrating the operability of the AFW system. Based upon the results of the Phase I study, the areas that appear to be inadequately monitored (e.g., governor controls/I&C for the turbine), as well as areas in which the level of testing appears excessive (e.g., stroking of the T&T valve), should be specifically addressed.

   b. the development of recommended changes, based upon the results of item a, to monitoring/operating practices and requirements to ensure that appropriate attention is provided to historically significant sources of AFW system degradation, while minimizing unnecessary testing (and the accompanying test-related wear).

2. Conduct a Phase I study of the AFW turbine drive. Because of the similarity of the AFW turbines to safety-related turbines used in BWR systems, a review of safety-related turbine drives in general should be considered.

3. Because of the significance of turbine governor and I&C related problems found in both the failure data and the Plant A reviews, consideration should be given to the conduct of a Phase I study of governors and their controls. Governors used on AFW turbines, as well as BWR safety-related pump turbines, emergency diesels, and diesel-driven pumps should be considered for inclusion in this study.

APPENDIX A
RELEVANT TECHNICAL SPECIFICATIONS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated flow paths shall be OPERABLE with:

a. Two motor-driven auxiliary feedwater pumps, each capable of being powered from separate shutdown boards, and

b. One turbine-driven auxiliary feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable, be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective action to restore at least one auxiliary feedwater pump to OPERABLE status as soon as possible.

SURVEILLANCE REQUIREMENTS

4.7.1.2 In addition to the requirements of Specification 4.0.5 each auxiliary feedwater pump shall be demonstrated OPERABLE by:

a. Verifying that :

1. each motor-driven pump develops a differential pressure of greater than or equal to __ psid on recirculation flow.

2. the steam-turbine driven pump develops a differential pressure of greater than or equal to __ psid on recirculation flow when the secondary steam supply pressure is greater than __ psig. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

3. each automatic control valve in the flow path is OPERABLE whenever the auxiliary feedwater system is placed in automatic control or when above 10% of RATED THERMAL POWER.

b. At least once per 18 months during shutdown* by:

1. Verifying that each automatic valve in the flow path actuates to its correct position upon receipt of an auxiliary feedwater actuation test signal and a low auxiliary feedwater pump suction pressure test signal.

2. Verifying that each auxiliary feedwater pump starts as designed automatically upon receipt of each auxiliary feedwater actuation test signal.

c. At least once per 7 days by verifying that each non-automatic valve in the auxiliary feedwater system flowpath is in its correct position.

*The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 for the turbine-driven Auxiliary Feedwater Pump.

BASIS

The OPERABILITY of the auxiliary feedwater system ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of off-site power.

The steam driven auxiliary feedwater pump is capable of delivering __ gpm (total feedwater flow) and each of the electric driven auxiliary feedwater pumps are capable of delivering __ gpm (total feedwater flow) to the entrance of the steam generators at steam generator pressures less than __ psia. At __ psia the open steam generator safety valve(s) are capable of relieving at least _% nominal steam flow. A total feedwater flow of __ gpm at pressures less than __ psia is sufficient to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F where the Residual Heat Removal System may be placed into operation.

NOTE: Some values are omitted in order to maintain anonymity for Plant A.

CONDENSATE STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The condensate storage tank system (CST) shall be OPERABLE with a contained water volume of at least ___ gallons of water.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With the condensate storage tank system inoperable, within 4 hours either:

a. Restore the CST to OPERABLE status or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours, or

b. Demonstrate the OPERABILITY of the emergency service water system as a backup supply to the auxiliary feedwater pumps and restore the condensate storage tank to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3.1 The condensate storage tank system shall be demonstrated OPERABLE at least once per 12 hours by verifying the contained water volume is within its limits when the system is the supply source for the auxiliary feedwater pumps.

4.7.1.3.2 The emergency service water system shall be demonstrated OPERABLE at least once per 12 hours by verifying that the emergency service water system is in operation whenever it is the supply source for the auxiliary feedwater pumps.

APPLICABILITY

SURVEILLANCE REQUIREMENTS

4.0.4 Entry into an OPERATION MODE or other specified condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the specified surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a (g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4 and with RESPONSE TIMES as shown in Table 3.3-5.

APPLICABILITY: As shown in Table 3.3-3

ACTION:

a. With an ESFAS instrumentation channel or interlock trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint value.

b. With an ESFAS instrumentation channel or interlock inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each ESFAS instrumentation channel and interlock shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the interlocks shall be demonstrated OPERABLE during the automatic actuation logic test. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" Column of Table 3.3-3.

TECH SPEC TABLE 3.3-3 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (AFW RELATED PORTION ONLY)

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
AUXILIARY FEEDWATER					
a. Manual Initiation	2	1	2	1, 2, 3	1
b. Automatic Actuation Logic	2	1	2	1, 2, 3	2
c. Main Stm Gen Water Level Low-Low					
i. Start Motor Driven Pumps	3/stm. gen.	2/stm. gen. any stm. gen.	2/stm. gen.	1, 2, 3	3
ii. Start Turbine Driven Pump	3/stm. gen.	2/stm. gen. any 2 stm. gen.	2/stm. gen.	1, 2, 3	3
d. S.I. Start Motor Driven Pumps and Turbine Driven Pump	(References the Safety Injection channel operability requirements)				
e. Station Blackout Start Motor Driven Pump associated with the shutdown board and Turbine Driven Pump	2/shutdown board	1/shutdown board	2/shutdown board	1, 2, 3	4
f. Trip of Main Feedwater Pumps Start Motor Driven Pumps and Turbine Driven Pump	1/pump	1/pump	1/pump	1, 2	4
g. Auxiliary Feedwater Suction Pressure-Low	3/pump	2/pump	2/pump	1, 2, 3	4

TECH SPEC TABLE 3.3-4 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS (AFW RELATED PORTION ONLY)

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
AUXILIARY FEEDWATER		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Main Stm Gen Water Level Low-Low	≥ __% of narrow range instrument span each SG	
d. S.I.	(References the Safety Injection Setpoints requirements)	
e. Station Blackout	__ volts with a __ second time delay	__ volts with a __ second time delay
f. Trip of Main Feedwater Pumps	Not Applicable	Not Applicable
g. Auxiliary Feedwater Suction Pressure-Low	≥ __ psig (motor driven pump) ≥ __ psig (turbine driven pump)	≥ __ psig (motor driven pump) ≥ __ psig (turbine driven pump)

TECH SPEC TABLE 3.3-5 ENGINEERED SAFETY FEATURES RESPONSE TIMES (AFW RELATED PORTIONS ONLY)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Auxiliary Feedwater Pumps	Not Applicable
2. Containment Pressure-High Auxiliary Feedwater Pumps	≤ 60
3. Pressurizer Pressure-Low Auxiliary Feedwater Pumps	≤ 60
4. Differential Pressure Between Steam Lines-High Auxiliary Feedwater Pumps	≤ 60
5. Steam Flow in Two Steam Lines - High Coincident with T_{avg} - Low-Low Auxiliary Feedwater Pumps	≤ 60
6. Steam Flow in Two Steam Lines - High Coincident with Steam Line Pressure-Low Auxiliary Feedwater Pumps	≤ 60
7. Main Steam Generator Water Level - Low-Low	
a. Motor driven Auxiliary Feedwater Pumps(1)	≤ 60
b. Turbine driven Auxiliary Feedwater Pump(2)	≤ 60
8. Station Blackout Auxiliary Feedwater Pumps	≤ 60
9. Trip of Main Feedwater Pumps Auxiliary Feedwater Pumps	≤ 60

(1) On 2/3 any Steam Generator
(2) On 2/3 in 2/4 Steam Generator

TECH SPEC TABLE 4.3-2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS (AFW RELATED PORTION ONLY)

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
AUXILIARY FEEDWATER				
a. Manual	N.A.	N.A.	R	1, 2, 3
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
c. Main Steam Generator Water Level Low-Low	S	R	Q	1, 2, 3
d. S. I.	(References the Safety Injection instrumentation surveillance requirements)			
e. Station Blackout	N. A.	R	N. A.	1, 2, 3
f. Trip of Main Feedwater Pumps	N. A.	N. A.	R	1, 2
g. Auxiliary Feedwater Suction	N. A.	R	M	1, 2, 3

PERTINENT TECH SPEC DEFINITIONS

CHANNEL CALIBRATION

A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

ENGINEERED SAFETY FEATURE RESPONSE TIME

The ENGINEERED SAFETY FEATURE RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

OPERABLE - OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s), and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s).

PERTINENT TECH SPEC DEFINITIONS

CHANNEL CALIBRATION

A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

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OPERATIONAL MODES

MODE		REACTIVITY CONDITION, K_{eff}	%RATED THERMAL POWER*	AVERAGE COOLANT TEMPERATURE
1.	POWER OPERATION	$\geq$0.99	>5%	$\geq$ 350°F
2.	STARTUP	$\geq$0.99	$\leq$5%	$\geq$ 350°F
3.	HOT STANDBY	<0.99	0	$\geq$ 350°F
4.	HOT SHUTDOWN	<0.99	0	350°F>T_{avg}>200°F
5.	COLD SHUTDOWN	<0.99	0	$\leq$140°F
6.	REFUELING	<0.95	0	$\leq$140°F

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours
M	At least once per 31 days
Q	At least once per 92 days
R	At least once per 18 months
N.A.	Not applicable

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10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

This report documents the results of a study of the Auxiliary Feedwater (AFW) System that has been conducted for the U. S. Nuclear Regulatory Commission's Nuclear Plant Aging Research Program. The study reviews historical failure data available from the Nuclear Plant Reliability Data System, Licensee Event Report Sequence Coding and Search System, and Nuclear Power Experience data bases. The failure histories of AFW System components are considered from the perspectives of how the failures were detected and the significance of the failure. Results of a detailed review of operating and monitoring practices at a plant owned by a cooperating utility are presented. General system configurations and pertinent data are provided for Westinghouse and Babcock and Wilcox units.

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